ULTRA-SUPERCRITICAL PRESSURE
CFB BOILER
CONCEPTUAL DESIGN STUDY

FINAL REPORT

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Abstract

Electric utility interest in supercritical pressure steam cycles has revived in the United States after waning in the 1980s. Since supercritical cycles yield higher plant efficiencies than subcritical plants along with a proportional reduction in traditional stack gas pollutants and CO_2 release rates, the interest is to pursue even more advanced steam conditions. The advantages of supercritical (SC) and ultra supercritical (USC) pressure steam conditions have been demonstrated in the high gas temperature, high heat flux environment of large pulverized coal-fired (PC) boilers.

Interest in circulating fluidized bed (CFB) combustion, as an alternative to PC combustion, has been steadily increasing. Although CFB boilers as large as 300 MWe are now in operation, they are drum type, subcritical pressure units. With their sizes being much smaller than and their combustion temperatures much lower than those of PC boilers (~300 MWe versus 1,000 MWe and ~1600ºF versus 3500ºF), a conceptual design study was conducted herein to investigate the technical feasibility and economics of USC CFB boilers.

The conceptual study was conducted at 400 MWe and 800 MWe nominal plant sizes with high sulfur Illinois No. 6 coal used as the fuel. The USC CFB plants had higher heating value efficiencies of 40.6 and 41.3 percent respectively and their CFB boilers, which reflect conventional design practices, can be built without the need for an R&D effort. Assuming construction at a generic Ohio River Valley site with union labor, total plant costs in January 2006 dollars were estimated to be $1,551/kW and $1,244/kW with costs of electricity of $52.21/MWhr and $44.08/MWhr, respectively.

Based on the above, this study has shown that large USC CFB boilers are feasible and that they can operate with performance and costs that are competitive with comparable USC PC boilers.

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1.0 Introduction

Coal is the largest source of fuel for electric power generation and it provides approximately 38 percent of the energy consumed in power plants worldwide. With the largest share of the world's recoverable coal reserves, the United States (US) generates over half of its electricity from coal. Coal is expected to remain the dominant fuel for power generation in the US for decades to come, not only because of its low and stable price, but also because energy diversity is a crucial and fundamental national security need.

Today's coal based power generation technologies, however, must prove their market competitiveness and gain public acceptance in a changing environment that entails:

- Deregulation and privatization that are transforming the electrical utilities from a regulated industry to a "bottom line" business keenly focused on costs and risks;
- Steady growth in electricity demand;
- Volatility in natural gas price;
- Concerns of ozone, particulate matter and trace metal pollution have led to drastically tightened NOx and SO_2 emission limits and utility mercury emission regulation;
- Current and anticipated requirements for reductions in CO_2 emissions or CO_2 intensity.

SO_2 and NOx emission credits are tradable commodities in the US. The mercury rule issued by the US Environmental Protection Agency, and the likely future CO_2 regulations, will be of the cap and trade type. In addition, the new emission limits also tend to be based on electric output rather than heat input. Because of the new regulatory trends, emission performance is now directly linked to plant efficiency and generation cost.

Today's utility industry is expecting new generation technologies to have low cost, high efficiency, high reliability, and good fuel flexibility while complying with future environmental regulations, including mercury and CO_2. Circulating fluidized bed (CFB) boilers with ultra-supercritical (USC) steam conditions have the potential to meet the above requirements and to become a preferred coal-based power generation technology.

The objective of this conceptual design study is to evaluate the feasibility of USC CFB boilers for large-scale power generation and identify any technical obstacles impeding their deployment.

1.1 Supercritical Pressure Pulverized Coal-Fired Boiler Technology

The Rankine cycle used by pulverized coal-fired (PC) power plants has been the dominant method for electricity generation through the last century. As steam cycle/boiler outlet conditions have steadily advanced to higher pressures and temperatures, plant efficiencies and economics have likewise improved.

As shown in Figures 1.1.1 through 1.1.3 extracted from [1-1], by 1950 Rankine cycle based steam power plants had reached steam conditions comparable to that of today's typical, sub-critical pressure power plants (2400 psig and 1000ºF). These plants had net efficiencies in the low 30s and further gains were achieved by moving from sub-critical to supercritical pressure steam conditions. As a result, boilers changed from drum type units that relied on the natural circulation of water through their evaporating tubes to forced circulation units wherein the water was pumped through those tubes at pressures well above the steam critical pressure point (3206 psia and 705ºF).

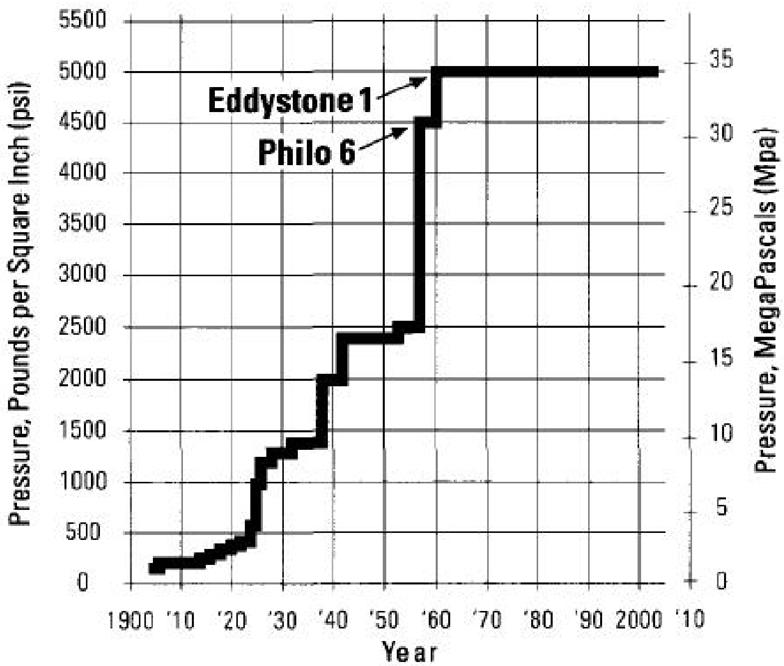


Figure 1.1.1 Power Plant Pressure Trends

The critical steam barrier was broken in the late 1950s with the introduction of several commercial supercritical steam power plants, most notably of these were the 85 MWe unit at Chemische Werke Huls in Germany, the 125 MWe Unit #6 at the Philo plant in Ohio, and the 325 MWe Unit #1 at the Eddystone Station in Pennsylvania.

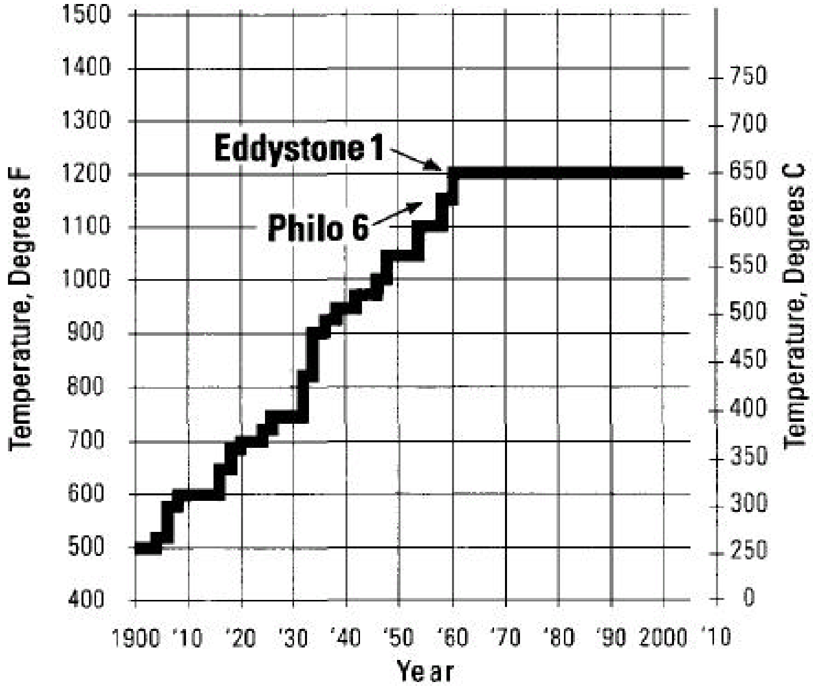


Figure 1.1.2 Power Plant Steam Temperature Trends

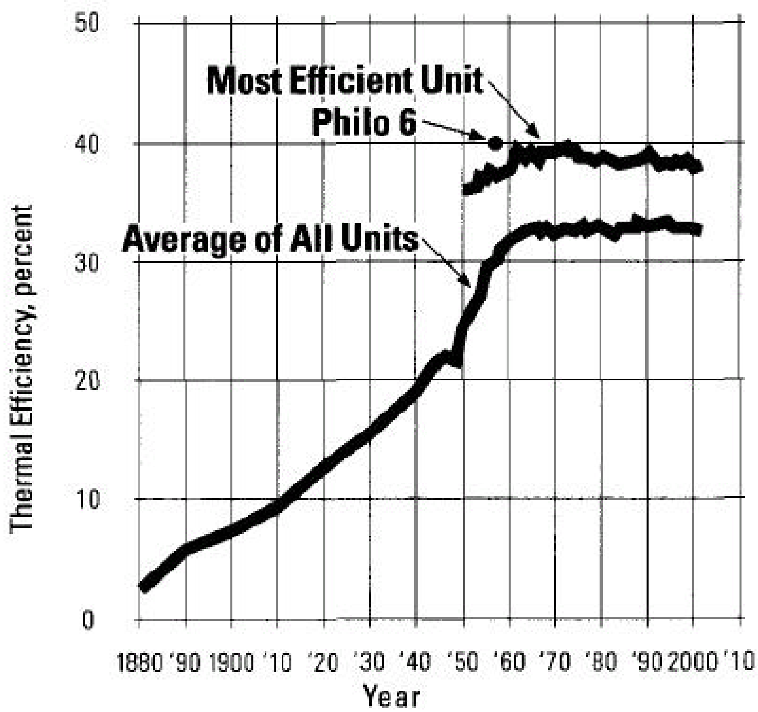


Figure 1.1.3 Power Plant Efficiency Trends

The referenced pioneering units represented a giant step forward from subcritical to what is today categorized as “ultra-supercritical” conditions (final steam temperature of 1100ºF and higher). All three plants incorporated double reheat steam cycles. Chemische Werke Huls design steam conditions are 4500psig / 1083ºF-SH / 1040ºF-RH1 / 1040ºF-RH2; Philo 6’s design conditions are 4500psig / 1150ºF-SH / 1050ºF-RH1 / 1000ºF-RH2 and Eddystone 1’s are 5000psig / 1200ºF-SH / 1050ºF-RH1 / 1050ºF-RH2.

However, these and other “first generation” supercritical plants did not fully demonstrate their commercial viability. Their boilers, steam turbines and steam piping/valves suffered from low reliability. The boiler related problems included superheater corrosion and waterwall fatigue cracking and some of these early units had to reduce their operating steam temperature and pressure.

In the 1960s numerous “second generation” supercritical units, representing about half of all utility fossil fueled boilers ordered, were built in the US. These second generation units incorporated lessons learned from the pioneering plants and they also chose more conservative steam conditions, typically 3500 psig and 1000ºF with single reheat cycles.

The popularity of supercritical units in the US dwindled through the 1970s, due to a number of reasons, including:

- The supercritical units under-performed their subcritical counterparts in terms of reliability and availability and led to a negative perception of supercritical technology by many utilities.
- Without the benefits of today’s advanced control systems, the complex controls of the once-through units presented additional challenge for plant operation, especially during start-up.
- The increasing share of base-loaded nuclear power stations in the generation capacity mix required that new fossil fueled plants have nimble load following and cycling capability – a weak area of early supercritical units with their thick pressure parts and typically constant pressure operation.

From the early 1980s through the 1990s, the combined effects of slow growth in electricity demand and new environmental regulations virtually brought the construction of large, US coal-fired power plants to a halt. Development and advances in supercritical technology, however, continued during this time period in Europe and Japan, where the need for high efficiency was driven by high fuel costs and a desire for reduced emissions. Advances in high temperature materials and design improvements, including the wide use of sliding pressure operation, have greatly enhanced the reliability, availability, operating flexibility, and efficiency of those new supercritical units; as a result, they have become the preferred technology for large scale, coal-fired power generation in several countries. In the past decade, supercritical units captured the dominant share of the world’s new coal-fired units (most of the activities are outside of US). Currently there are about 520 supercritical units in operation worldwide located in Germany, Denmark, Japan, former Soviet Union, China, Korea, and including 160 older units in US.

Table 1.1.1 is a listing of recent supercritical units that have been commissioned or are under construction. These projects are characterized by large unit sizes (up to 1000 MWe), and high steam temperatures (1100ºF or higher). It is also noted that all but two Danish units are with single reheat arrangement.

Table 1.1.1 Recent Supercritical PC Boilers

Unit Name	Size, MWe	Design Steam Pres., psia	Steam Temperatures, SH/RH1/RH2, F	Commission-ing Year	Fuel	Country
Misumi	1000	3568	1112 / 1112	1998	Coal	Japan
Nordjyllandsvaerket	410	4496	1080 / 1076 /1076	1998	Coal	Denmark
Skaerbaekvaeket	410	4496	1080 / 1076 /1076	1999	Coal	Denmark
Suizhou 1, 2	2x800	3626	1013 / 1013	2000	Coal	China
Schwarze Pumpe	2x800	3626	1011 / 1043	2000	Lignite	Germany
Boxberg	2x900	4134	1013 / 1080	2000	Lignite	Germany
Lippendorf	2x930	4134	1029 / 1081	2000	Lignite	Germany
Tachibana-Wan 2	1050	3626	1112 / 1130	2001	Coal	Japan
Tsuruga 2	700	3495	1103 / 1103	2001	Coal	Japan
Isogo No.1	600	3986	1121 / 1135	2002	Coal	Japan
Niederaussem K	1000	3981	1076 / 1112	2002	Lignite	Germany
Avedoe	415	4670	1080 / 1112	2002	Coal	Denmark
Bexbach II	750	3626	1067 / 1103	2002	Coal	Germany
Hitachi-Naka 1	1000	3684	1119 / 1116	2003	Coal	Japan
Waigaoqiao 1, 2	2x900	3626	1000 / 1050	2003	Coal	China
Shinko Kobe 1, 2	2x700	3626	1008 / 1054	2002, 2004	Coal	Japan
Hirono 5	600	3553	1112 / 1112	2004	Coal	Japan
Maizuru	900	3553	1103 / 1103	2004	Coal	Japan
Yonghungdo 1, 2	2x800	3500	1050 / 1050	2004	Coal	Korea
Wesfalen	350	4206	1112 / 1148	2004	Coal	Germany
Yuhuan 1, 2	2x1000	3807	1112 / 1112	2007	Coal	China

The latest development in supercritical boiler technology is the market entrance of the once through, supercritical CFB boiler. This 460 MWe CFB was awarded to Foster Wheeler for the Lagisza project in Poland [1-2] and is presently scheduled for a year 2009 start-up. The Lagisza CFB unit is designed for 3974 psig with superheat and reheat steam temperatures of 1040ºF and 1076ºF respectively and it will utilize the Low Mass Flux, Benson Vertical Once-Through Technology developed by Siemens AG; this technology is described further below.

1.2 Circulating Fluidized Bed Boiler Technology Overview

There are three major solid fuel combustion technologies in use today for generating steam. Stoker firing burns fuel crushed up to a 1 inch maximum size in a fixed bed mode. Although it is a traditional technology, it is no longer used for large power station boilers because of its low combustion efficiency. PC furnaces combust coal, crushed to a fine powder (typically 75 percent passing through a 200 mesh screen), as an air entrained mixture. PC combustion was first introduced in the 1800s, and in the 1920 to 1970 time period it gained and has maintained the dominant position for solids fuel power generation in the 100 MWe to 1300 MWe size range. CFB combustion technology has developed rapidly in the past three decades and is becoming an important technology for large-scale power generation.

There are three important modes of fluidized bed operation, the bubbling fluidized bed (BFB), the CFB, and the fast fluidized bed. The bubbling bed operates at lower gas velocities, typically up to 6 feet per second, with the solids particles suspended by the drag of the up-flowing gas. This gas-solids suspension or "emulsion" forms the continuous phase known as the "bed" at the bottom of the reactor and any excess gas passes through the bed in the form of discrete, rising bubbles. In the fast bed mode, gas velocities are much higher, typically above 40 feet per second, and the reactor is filled with an entrained flow of solids and gas. A CFB boiler operates at a lower velocity, typically about 20 feet per second, and the lower velocity yields heavy solids back mixing (refluxing) in the form of clusters / strands of particles that constantly change shape. Although a CFB boiler employs the fast bed principle in the combustor, it also uses the bubbling bed mode for solids return, fluidized bed heat exchangers, and ash coolers.

The bubbling bed was first used for coal combustion and steam generation. Development began during the 1960s in China, the United Kingdom, and US and, since then, hundreds of small BFB boilers have been built worldwide with capacities up to 180 MWe. As a power generation option, however, the BFB has been eclipsed by the CFB boiler as the latter offers superior combustion and emission performance, a more compact combustor size, and avoids the use of erosion-prone in-bed tubes. Today BFB boilers remain a niche product for relatively small size units burning biomass and other waste fuels with low heating value, low sulfur content, and high moisture content.

Interest in CFB combustion started in the 1970s with development work being carried out by several different groups. A pilot plant was constructed at Foster Wheeler's Karhula Research and Development Center in Finland (formerly Hans Ahlstrom Laboratory) in 1976 to develop CFB combustion technology and this effort led to the start-up of Foster Wheeler's first commercial unit, rated at 15 MWt in 1979 at Pihlava Finland. Because of the CFB's multi-fuel capability, low emissions, operating flexibility, and high reliability, there has been a steady progression to larger unit sizes. Figure 1.2.1 shows the scale-up history of Foster Wheeler's CFB boilers and it is noted that over about a 30 year period there has been 60 fold increase in size e.g. from 5 MWe to 300 MWe. Excluding China (because of a lack of data) there are currently over 450 CFB boilers in operation worldwide. Foster Wheeler has supplied over 200 of these CFB units. Other major vendors include Alstom, Kvaerner, Lurgi, Babcock & Wilcox, and several domestic boiler companies in China. Today the largest CFB boilers in operation are the two 300 MWe boilers Foster Wheeler supplied to the Jacksonville Electric Authority (JEA) in Florida [1-3]. The rapid scale-up of CFB technology received important assistance from the US Government through a number of US DOE Clean Coal Demonstration Projects, including such milestones as the first 100 MWe class unit at Tri-State, and the first 300 MWe class units at Jacksonville.

The first generation of CFB boilers used conventional cyclone designs to recirculate hot solids back to the base of their combustor. Those cyclones were fabricated from carbon steel and contained thick, internal, multi-layer refractory linings to protect their casings from erosion and the high process temperatures. The heavy refractory linings, however, required slow heat-up rates at start-up and this, together with their high maintenance needs, reduced unit availability and operating flexibility. To overcome these shortcomings an improved, second generation design was developed by Foster Wheeler that formed the cyclone walls from steam cooled tubes/panels. With the walls now cooled, only a minimum amount of refractory is needed for erosion protection (~1 inch) and CFB technology has moved to integrate the solids separator with the combustion chamber; with the cooled separator and furnace walls operating at similar temperatures, the need for expansion joints is minimized and the horizontal distance that circulating solids must transverse is reduced.

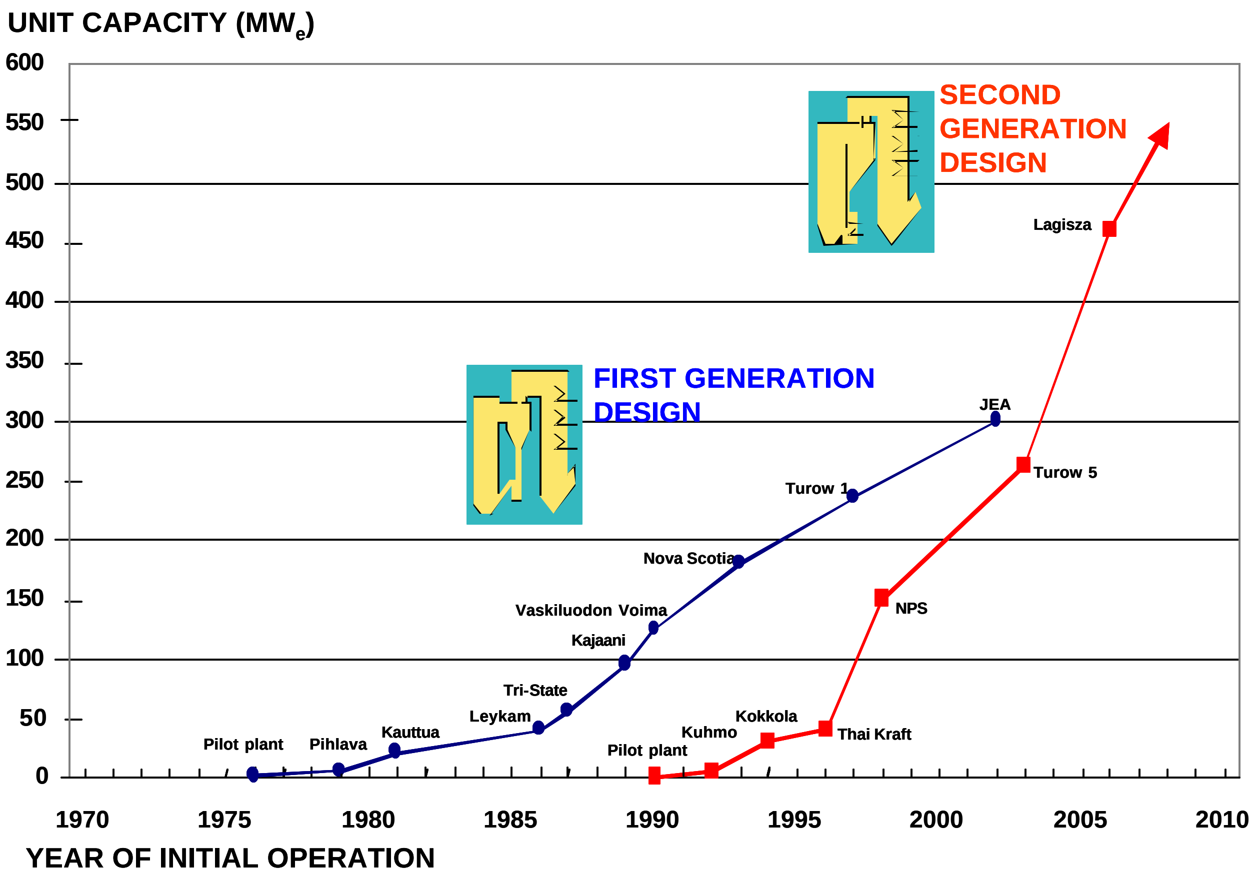


Figure 1.2.1 Scale-Up History of Foster Wheeler CFB Boilers

The first of Foster Wheeler's second-generation CFB boilers was started in 1992 and the number and size of these units has grown steadily. The latest development in CFB boiler technology is the 460 MWe boiler for the Lagisza project in Poland. This unit, when commissioned, will be the world's largest CFB boiler as well as the first to operate with supercritical pressure steam.

1.3 Once-Through Boiler Technology

Overview

Boilers for utility power generation are configured as either natural circulation " drum" type or forced circulation "once-through" (OTU) type units. In drum-type units (see Figure 1.3.1) the steam flow rate is controlled by the fuel firing rate. Superheat steam temperature is determined by the proper sizing of the superheater heat transfer surface and controlled by spray water attemperation. The drum boilers are typically limited to main steam pressure below 2800 psig, because their natural circulation principle is based on the density difference between steam and water, which diminishes at higher pressures. In a once-through boiler, the steam flow rate is established by the feed water pump and the superheat steam temperature is controlled by the fuel firing rate. Since the once through boiler does not rely on the density difference between steam and water to provide proper circulation and cooling of the furnace enclosure tubes, it can be operated at pressures above the supercritical point. Operation above the critical pressure significantly increases the plant efficiency and results in reduced fuel consumption, less carbon dioxide production (green house effect), and lower emissions of SO_2 and NOx (acid rain) per megawatt of power output.

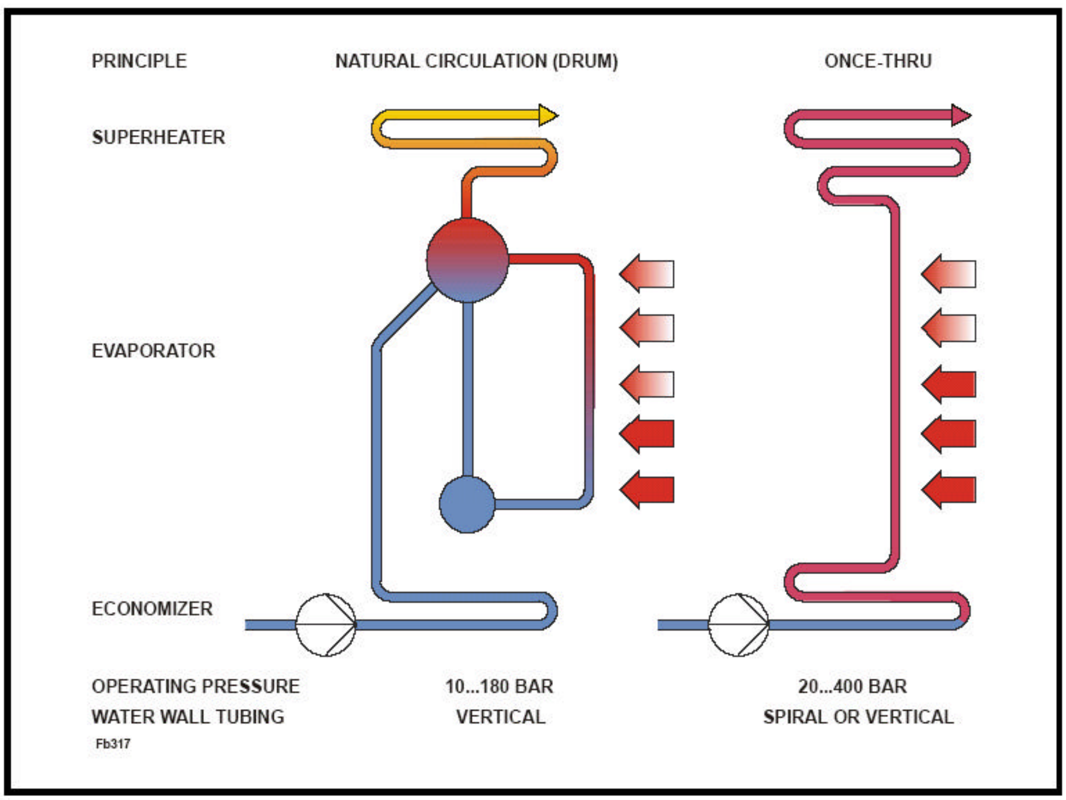


Figure 1.3.1 Utility Boiler Circulation Methods

In subcritical boilers evaporation/boiling occurs in the furnace enclosure wall tubes, all of which are cooled by a constant temperature (saturation), two phase, water-steam mixture. At supercritical conditions, however, there is no heat of vaporization and the fluid in individual tubes can have different temperatures that are determined by the amount of heat flux and cooling water flow they receive. Thus the primary design requirement for the furnace walls of supercritical boilers is to minimize peak tube metal temperatures while limiting the differential temperature between adjacent enclosure wall tubes. Historically, these issues are addressed by using high steam/water mass flow rates. To provide high mass flow rates, the evaporative furnace walls have been designed in several sequential fluid passes (see Figure 1.3.2) that reduce the fluid-temperature rise per pass. Complete mixing between passes minimizes the potential for large temperature unbalances. However, this type of an arrangement requires operation at supercritical pressure over the load range to avoid two-phase flow related problems that can occur when trying to distribute steam/water mixtures between passes. As a result, there is a throttling pressure loss during low load operation that results in a "part load" penalty in plant thermal efficiency.

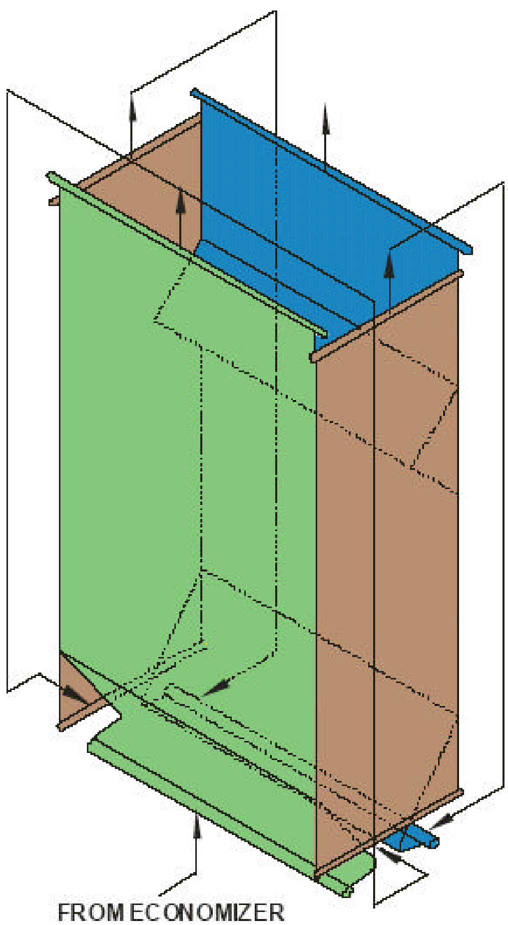


Figure 1.3.2 Multi-Pass Furnace Circuitry

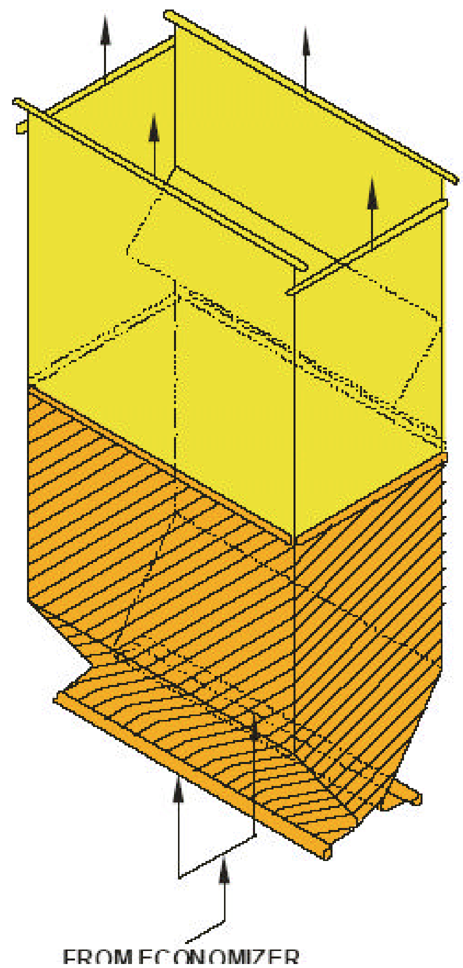


Figure 1.3.3 Spiral Furnace Circuitry

Another method for achieving high mass flow rates is to incline the furnace enclosure tubes in a single pass, spiral wound arrangement (see Figure 1.3.3). This allows the furnace walls to be formed from fewer tubes. Also, since all the tubes wrap around all the enclosure walls and corners, differences in tube heat absorption, and therefore tube metal temperature unbalances, are minimized. Since the furnace walls are covered by a single tube pass, there is no multi-pass mixing and the unit can operate at subcritical pressure during part load or cycling operation; as a result, part load cycle efficiency is improved and it is easier to match steam and turbine blade metal temperatures for improved steam turbine life

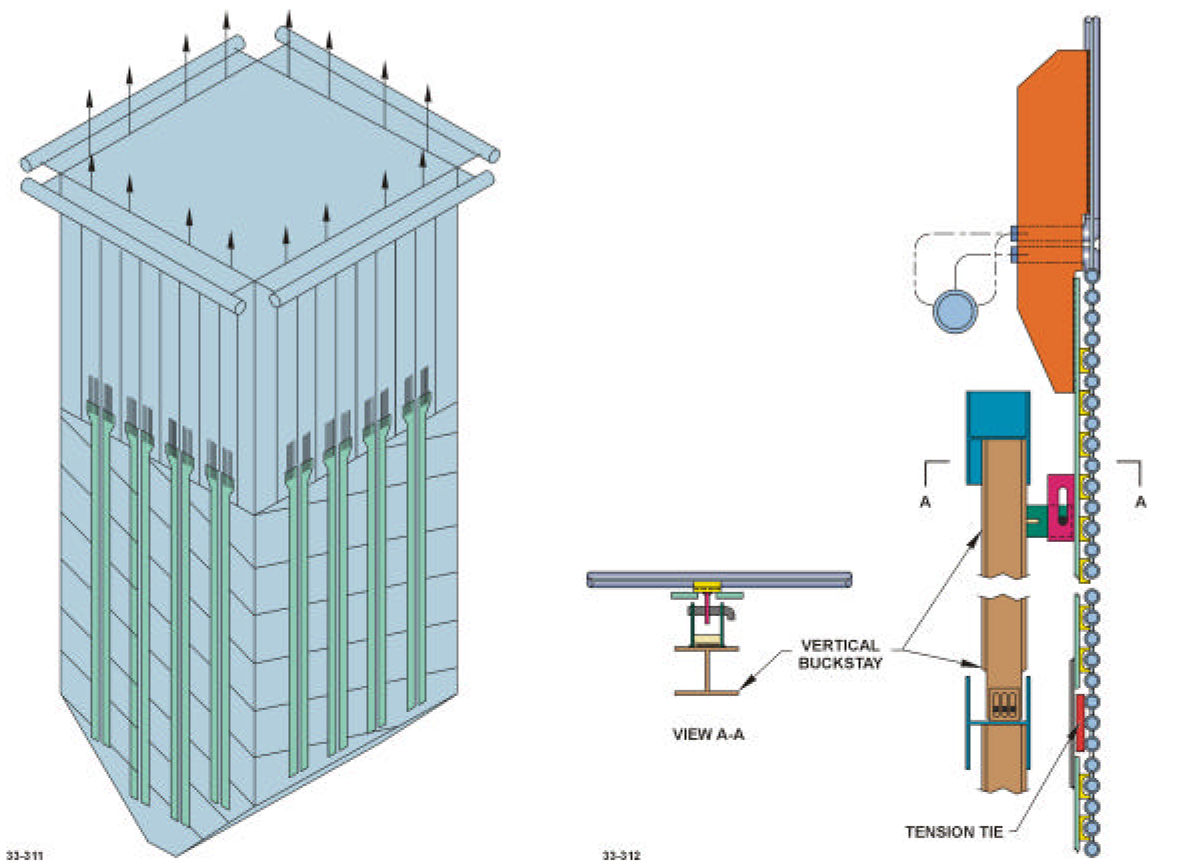


Figure 1.3.4 Special Support System for Spiral Furnace Tubes

One drawback of the spiral tube arrangement is its higher manufacturing and installation costs. The inclined tubes are not self-supporting and a special support system is needed (see Figure 1.3.4). This requires complex fabrication of the spiral tube panels and numerous field welds, leading to higher capital costs [1-4]. Despite their higher furnace costs, spiral-wound tubes have gained popularity in the past 30 years and, with several hundred in operation worldwide, they represent the current state-of-the-art.

Although popular for PC boiler construction, a spiral tube arrangement is not acceptable for CFB boiler application because the inclined enclosure tubes would be subject to erosion. In CFB boilers, fuel and sorbent ash are entrained in the flue gas that passes up through the furnace. A significant amount of the entrained solids reflux (fall down) along the furnace walls and any protrusion, which changes the direction of the falling solids, will be subject to erosion.

Benson Vertical Boiler Technology

The above spiral furnace design issues are avoided with the new BENSON Vertical technology developed by Siemens through extensive research and development, and field-testing. The BENSON Vertical design (see Figure 1.3.5) addresses the OTU design requirements in the following ways:

Differential Tube Temperature. In the Multi-Pass and Spiral furnace wall designs, peak and differential tube temperatures are limited by ensuring sufficiently high steam/water mass flow rates through the tubes over the operating load range. This mode of operation has what is termed a "once-through" characteristic wherein an excessively heated tube will experience a reduction in tube water flow that will increase tube metal temperatures. This phenomenon is illustrated in Figure 1.3.6a.

A strongly heated tube will have hotter fluid and therefore a lower density than occurs in the average tube. The pressure loss resulting from hydrostatic head will go down. However, because the fluid density is lower, fluid velocity will increase, increasing the friction pressure loss. Although there is a reduction in hydrostatic head, the increase in friction loss dominates and the circuit total pressure loss increases. The increased pressure loss will result in a reduction of flow in the excessively heated tube to maintain the average pressure loss in the circuit. This combination of high heat input with reduced flow can increase both steam and tube metal temperatures and result in tube failures.

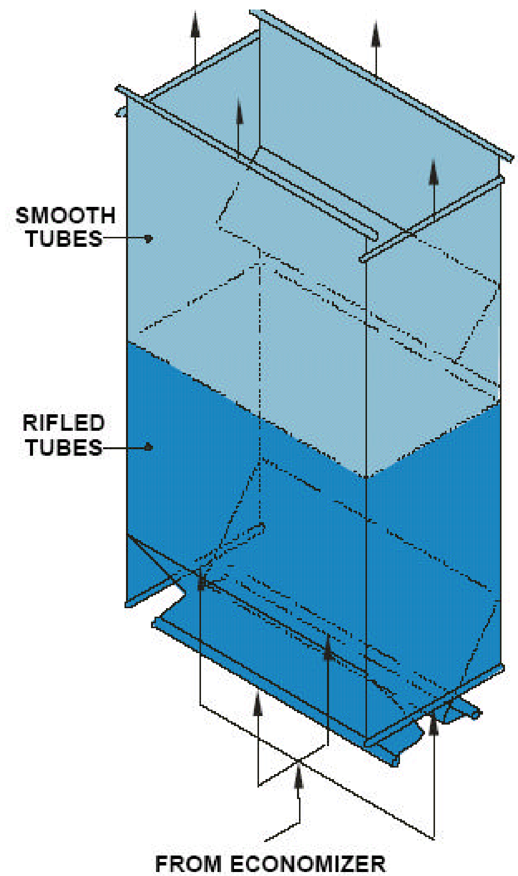


Figure 1.3.5 BENSON Vertical Furnace Circuitry

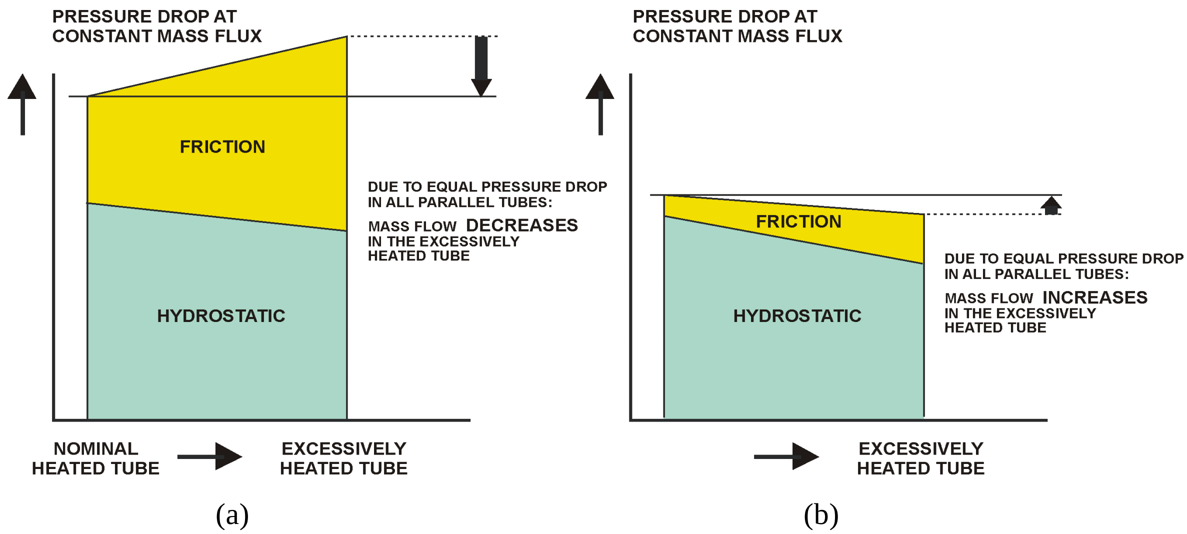


Figure 1.3.6 "Once-Through" (a) and "Natural Circulation" (b) Characteristics

In the BENSON Vertical design, the furnace vertical enclosure wall tubes are sized to yield a relatively low mass flow rate (about 200 lbs/sec/ft^2 or 1000 kg/sec/m^2) at full load. With the flow rate reduced, the tube friction loss is much smaller than the hydrostatic pressure effect. Although an increase in heat input still increases the friction loss, the increase is less than the reduction in hydrostatic pressure. With the tube total pressure loss now less than that of the average tube, the water flow rate to the tube will increase (see Figure 1.3.6b); this flow increase provides additional cooling that will help limit increases in tube metal temperatures. This is the "natural circulation" characteristic wherein an excessively heated tube will experience an increase in flow that tends to limit over heating.

Peak Tube Temperature. The normal drawback to using low fluid mass flow rates is that with smooth tubes, their inside heat transfer coefficients are reduced and departure from nucleate boiling (DNB) or dryout will occur at steam qualities that are lower than those of high mass flow rate tubes. With dryout occurring at a lower steam quality, it will occur lower in the furnace where heat fluxes are higher and, depending upon conditions, tube failures can result. To solve this problem Siemens has developed an optimized rifled tube design, named BENSON Vertical technology. In simplistic terms, the rifling is a roughening of the inside tube surface; it induces turbulence/mixing that disrupts boundary layer growth/the formation of poor heat conducting steam films at the tube inside surface.

As illustrated in Figure 1.3.7, dryout in a smooth tube can result at relatively low steam qualities. In the example illustrated, it occurs at about 55 percent quality at which point there is a sudden increase in tube wall temperature. With an optimized rifled tube, the tube wall can be kept wet to a steam quality over 90 percent even with low mass flow rates.

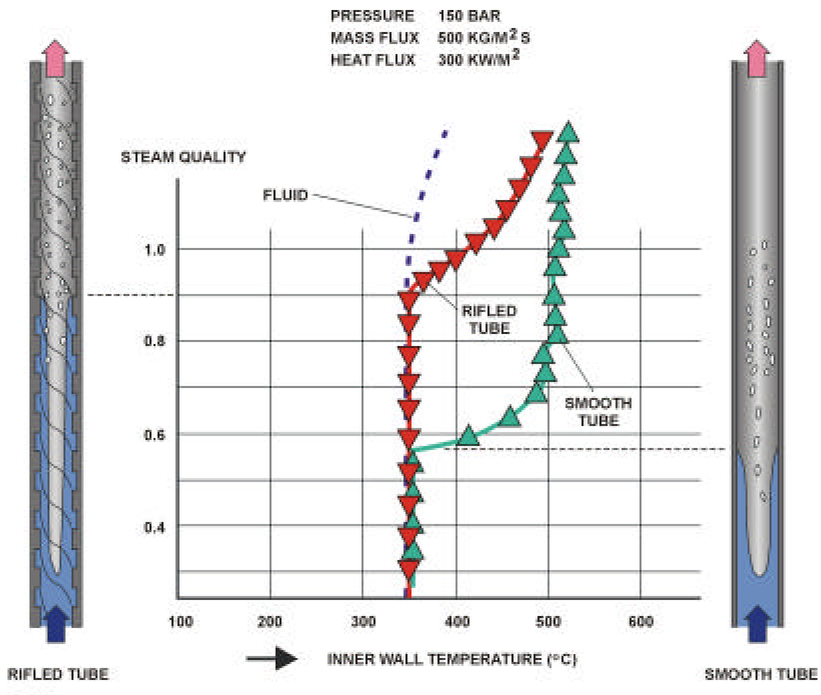


Figure 1.3.7 Rifled Tube Heat Transfer Improvement

Optimized Rifled Tube. Through extensive laboratory testing, Siemens has developed an optimum rifled tube design which, via a judicious selection of rib lead angle, height, and shape, provides the best combination of heat transfer and pressure loss. Their data has been correlated into advanced computerized software for thermal hydraulic analysis. Figure 1.3.8 compares an optimized rifled tube to both a standard rifled tube and a smooth tube all operating at the same mass flow rate. As can be seen, the optimized rifled tube results in the lowest tube temperature. The lower plot in Figure 1.3.8 shows that the mass flow rate of an optimized rifled tube (157 lb/sec/ft^2 or 770 kg/sec/m^2) can be significantly lower than that of a standard rifled tube (205 lb/sec/ft^2 or 1,000 kg/sec/m^2) as well as a smooth tube (307 lb/sec/ft^2 or l1,500 kg/sec/m^2) and still achieve the same level of tube cooling. Because of this, an optimized rifled tube can operate with the low mass flow rates that exhibit a "natural circulation" characteristic. The lower pressure loss provided by an optimized rifle tube results in a lower design pressure for the boiler thereby reducing pressure part weight, boiler feed pump auxiliary power, and the minimum BENSON load point (the latter will be discussed further below).

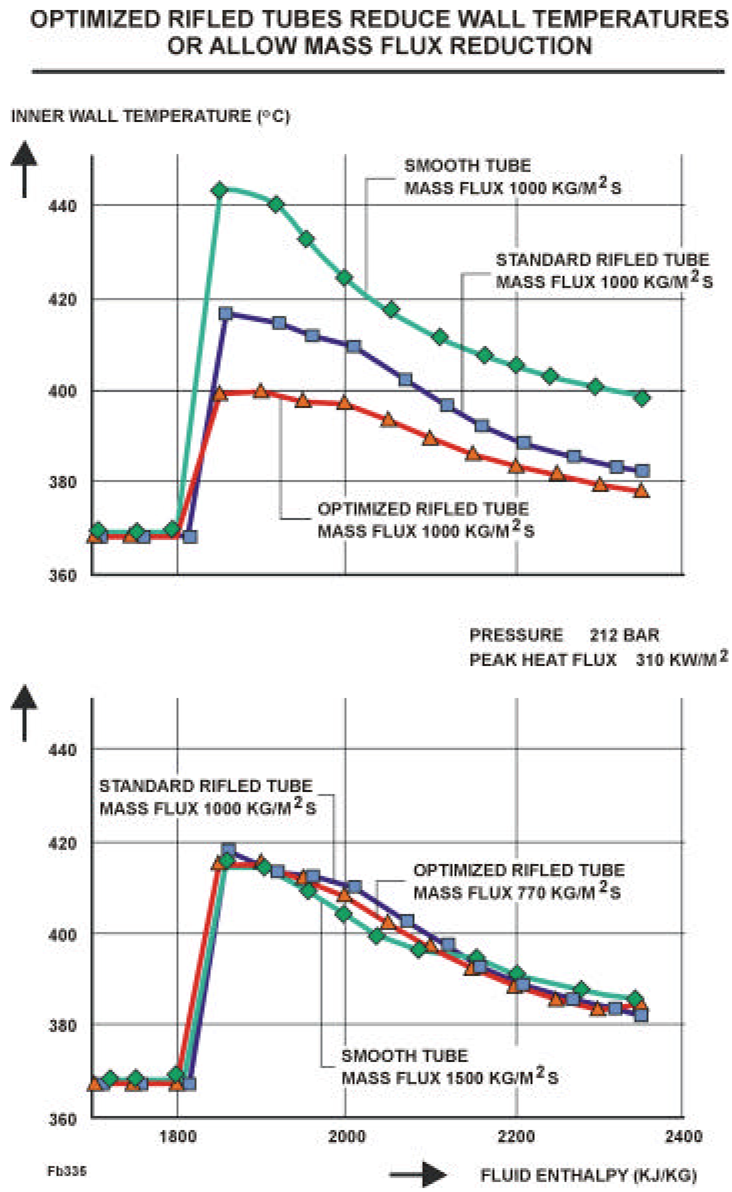


Figure 1.3.8 Optimized vs. Smooth and Standard Rifled Tubes

Simple Support. A main advantage of the BENSON Vertical design is that it can operate with full and variable furnace pressure for cycling service using vertical tubes with a standard, simple support system (see Figure 1.3.9). There is no associated limit on the change rate of waterwall fluid temperature due to fatigue limits of the support straps, since they are not required (Figure 1.3.4). Also, the load carrying ability of the furnace is greater in the event that slag should accumulate in the hopper of a PC boiler. If repair is required, standard, simple tube replacement procedures can also be used.

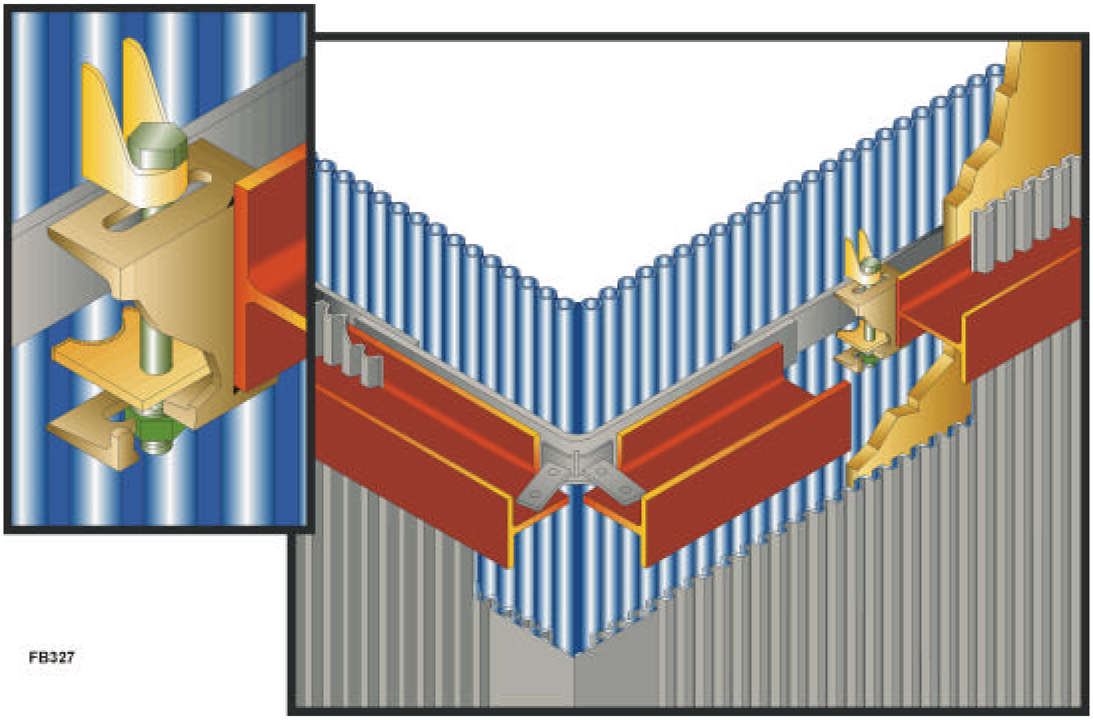


Figure 1.3.9 Typical Vertical Tube Support System

Start-Up System: To start-up a once-through boiler, the steam/water pressure parts and the steam turbine must be warmed and brought on-line in a safe, controlled manner that will not cause damage to any component. To do this, a load is established below which the unit is controlled as a drum type unit (firing for pressure/steam flow). In-line separators are provided downstream of the furnace tubes to collect steam for warming the superheater pressure parts and the steam turbine. Water collected by the separators is returned back to the furnace to maintain a minimum mass flow rate for proper tube cooling. Above this minimum load, the unit is operated and controlled as a once-through boiler firing for steam temperature. The value of this minimum once-through load (termed Benson load) and the type of start-up system used will depend on the furnace circuitry arrangement.

For a CFB BENSON Vertical boiler, the minimum BENSON load is usually established between 30 to 40 percent of full load. This requires establishing a minimum mass flow rate of 30 to 40 percent of the full load flow rate through the furnace walls. To achiever this, a recirculation pump superimposes a recirculating flow onto the flow provided by the boiler feed pump. Figure 1.3.10 illustrates the recirculation pump system. The economizer and evaporator circuitry are filled with water and a water level is established in the water collecting vessel. The boiler feed pump flow rate is set at a minimum flow and the recirculation pump is used to maintain the minimum load flow rate through the furnace enclosure walls. The flow leaving the furnace passes through several steam separators that operate in parallel (a typical 600 MWe unit would have four separators).

Water, collected by the separators, drains to a single collecting vessel and onto a single boiler recirculation pump that discharges to the economizer feed line. The water level in the collecting vessel is controlled by a valve that dumps excess water to a flash tank which in turn, discharges to a condensate tank; from the latter, the water can be discharged to atmosphere or pumped onto the deaerator, the feed water tank, and the boiler feed pump. During start-up, when furnace water flows are less than the boiler feed pump minimum allowed flow rate, a bypass line protects the feed pump by discharging the excess water flow to the water collecting vessel. Although not shown, low temperature feed water can be admitted to the collecting tank to prevent steam bubbles from forming in the recirculation pump suction line when saturation conditions are reached.

Steam, collected in the separators during start-up, flows through the superheater tube circuitry to keep their tube metal temperatures under control. Depending upon the plant design, the heated steam can be cooled by water spray and either cascaded to the cold reheat steam line or discharged to the condenser via bypass valving. During normal operation the superheater steam proceeds to the high pressure section of the steam turbine, returns to the boiler for reheating, proceeds to the intermediate/low pressure sections of the steam turbine, and then discharges to the condenser.

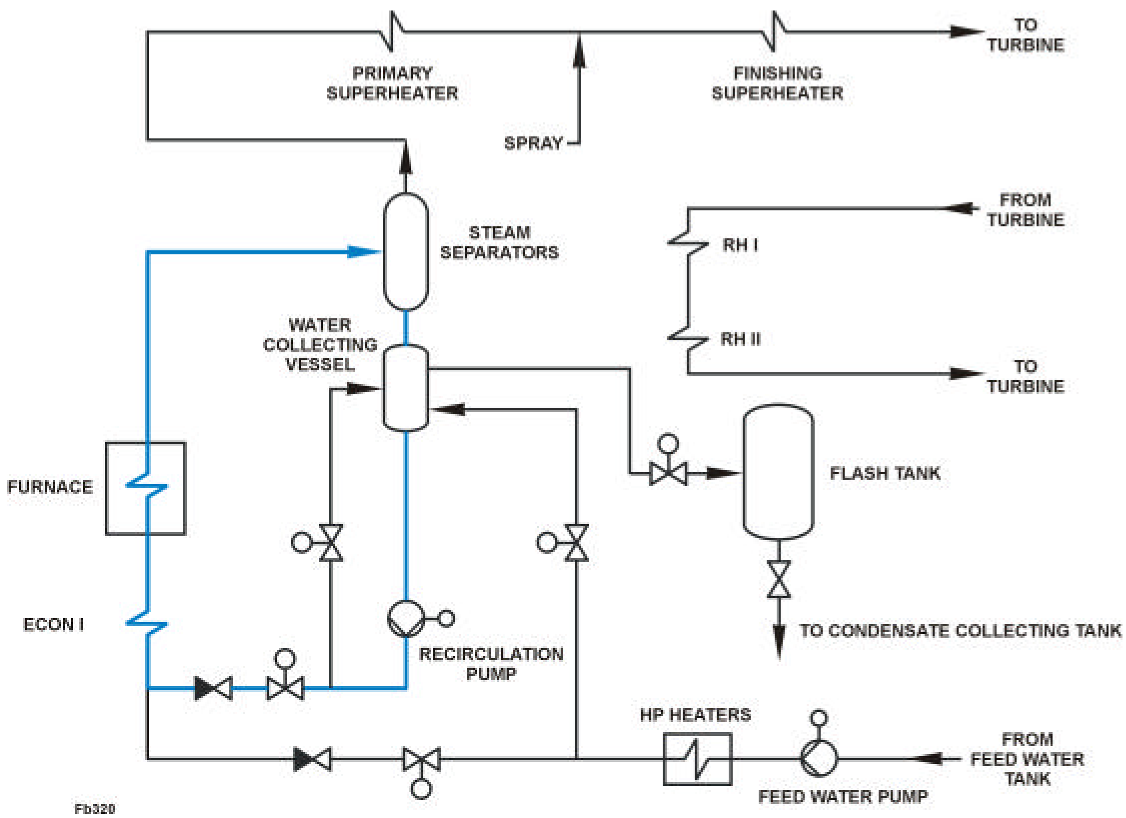


Figure 1.3.10 Recirculation Pump Start-Up System

A typical separator, called a tangential separator, is illustrated in Figure 1.3.11. Steam enters through either four (4) or six (6) inlet nozzles (depending on unit size) which are positioned tangentially around the vessel circumference. The orientation and size of the nozzles in combination with the vessel diameter and position of the vortex finder (upper steam discharge pipe) has been optimized by extensive testing by Siemens to provide a balance between pressure loss and steam separation efficiency. A vortex eliminator is provided near the water drain at the bottom of the vessel. Vessel diameter is limited to about 23 inches to limit vessel thickness so that it does not restrict allowable temperature change rates. Vessel length is typically about 13 feet.

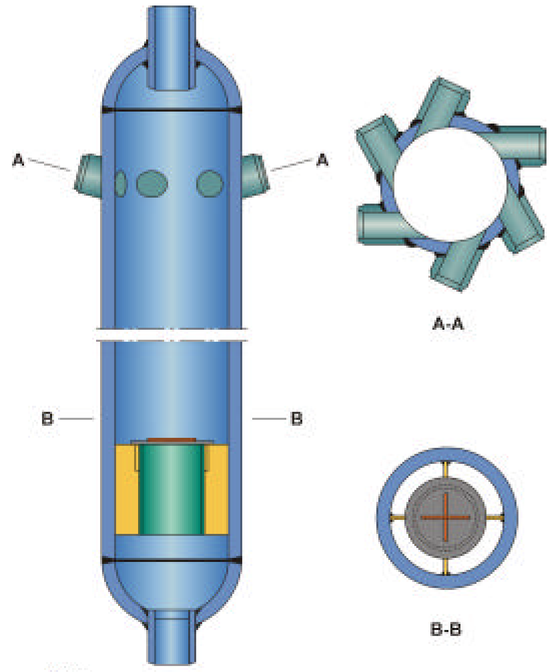


Figure 1.3.11 Typical Tangential Steam Separator

A typical water collecting vessel is illustrated in Figure 1.3.12. The vessel has the same diameter limits as the separators and is about 40 feet tall. It is equipped with a pressure equalizing line which vents any steam which may be carried along with the separated water. A vent line is connected to the steam discharge line from each separator.

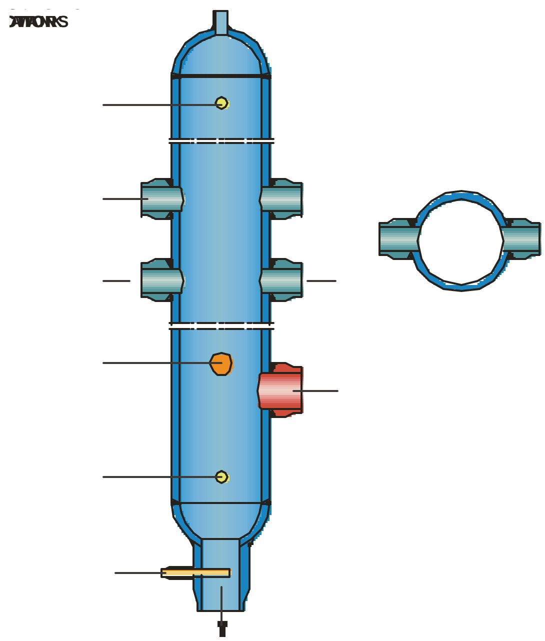


Figure 1.3.12 Typical Water Collecting Vessel

1.4 BENSON Optimized Rifling Not Required by CFB Boilers

The BENSON Vertical technology was initially developed for conventional PC, oil, or gas-fired utility boilers. A CFB furnace operates under considerably different and less severe heat flux conditions than a conventional PC furnace. In the CFB furnace or vertical riser section a significant portion of the combustion air is introduced as primary air through an air distribution grid at the base of the unit. This air lifts and puts into suspension the solids inventory of fuel, ash, and limestone that form the CFB. The balance of the combustion air (secondary air) is introduced about 6 feet above the air distributor to complete the combustion process and entrain the finer fraction of solid products. The gas entrained solids flow up through the furnace and enter separators that collect and return solids back to the lower furnace while discharging the flue gas to the heat recovery area (HRA). The collected solids establish a flywheel of circulating particulate that maintain relatively uniform vertical and radial temperature distributions throughout the furnace. For optimum capture of SO_2 by limestone, the furnace is maintained at a temperature of about 1560ºF to 1650ºF. This relatively low combustion temperature, together with the introduction of combustion air in stages, also minimizes the formation of NOx.

Since the CFB combustion temperature is relatively low and uniform, the heat flux to its furnace enclosure walls are considerably lower than those of a PC furnace (see Figure 1.4.1). In addition, up to 25 feet of the lower furnace height is covered by a relatively thin layer of refractory that protects the tubes from corrosion and erosion caused by localized substoichiometric conditions and circulating bed material. As a result, the heat absorption in this area is minimal and the highest heat fluxes occur just above the refractory protected area. In this transition region, there is a significant amount of refluxing (falling back) of strands of particles that are effectively too coarse to be carried off by the rising flue gas. Even though the heat transfer to the furnace walls is highest in this region, the ratio of the CFB's peak to average heat flux is still considerably lower than that of a PC furnace.

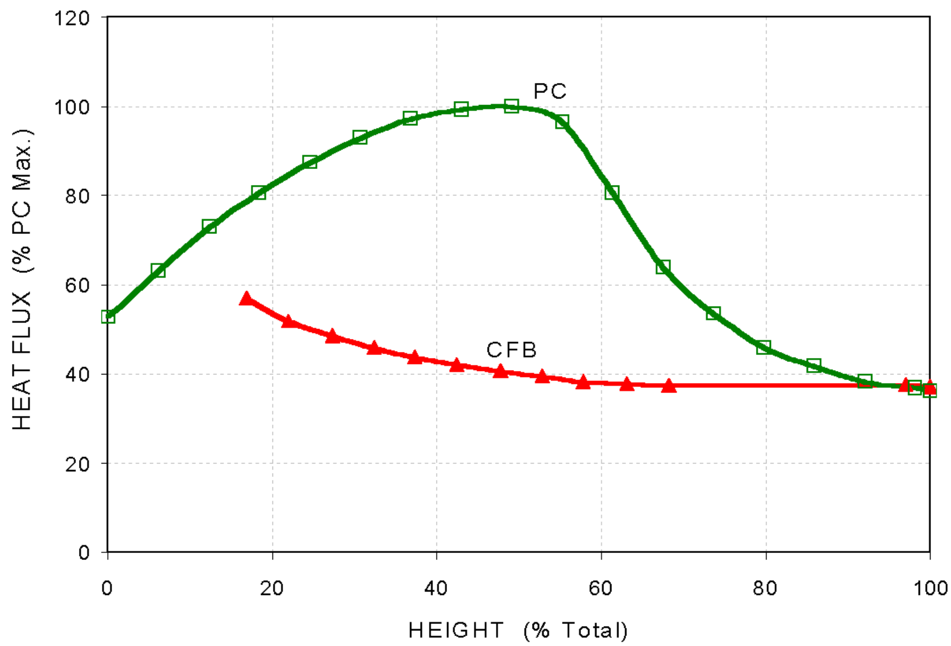
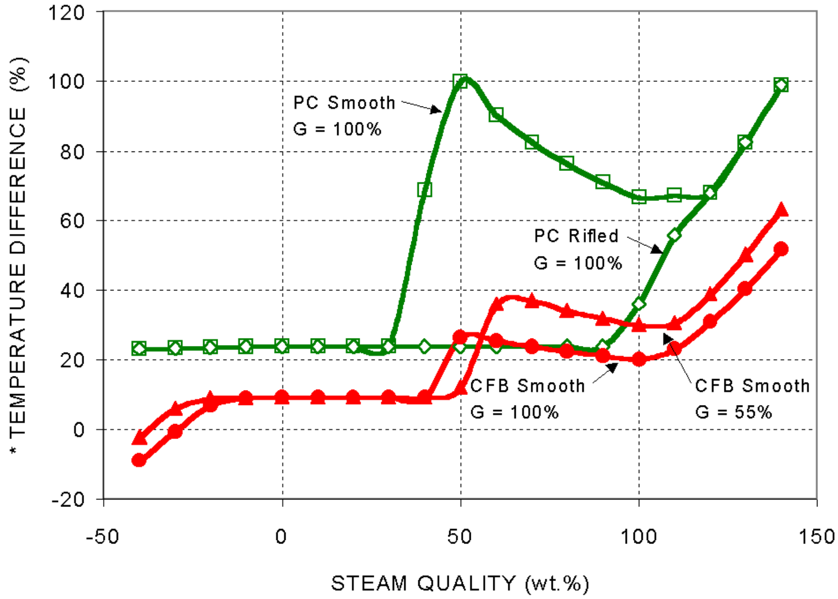


Figure 1.4.1 PC vs. CFB Heat Flux Distribution

Because CFB furnace heat fluxes are relatively low and uniform, its tubes can operate with water mass flow rates that are lower than those of a PC furnace and still be protected from DNB/dryout. A full load mass flow rate in the range of 100 to 140 lb/sec/ft^2 or 500 to 700 kg/sec/m^2 can be used to achieve the Figure 1.3.6 "natural circulation" characteristic. Figure 1.4.2 shows that for part load operation at subcritical pressure with smooth tubes and low mass flow rates (55 percent of that used for PC design), CFB furnace tubes do not experience a significant rise in tube temperature, even at dryout, because of the low heat fluxes.



* Note: Temperature Difference is between Mean Tube Metal and Saturated Fluid. PC Max. = 100%
65% load, P = 173 bar, peak heat flux conditions

Figure 1.4.2 Dryout at Subcritical Pressure

Another phenomenon that must be considered in boiler design is the DNB that can occur near the critical steam pressure. As the critical pressure is approached, the Leidenfrost temperature (tube wall temperature above which stable film boiling occurs) approaches the saturation temperature and this phenomenon is investigated in Figure 1.4.3. With the high heat fluxes of PC furnaces, DNB can occur near zero percent steam quality when operating in the critical pressure range (3,100 psia). By using optimized rifled tubing, heat transfer rates can be enhanced and PC furnace tube temperatures reduced.

For typical CFB operation, however, the heat fluxes experienced with smooth furnace enclosure wall tubes are not high enough to increase the tube wall temperature to that at which low steam quality film boiling occurs. As a result, the furnace walls of a CFB will not require Benson optimized rifle tubing. Evaporative tube surfaces that protrude into the furnace (see Figures 1.5.5 and 1.5.6), however, will be provided with normal rifling as, being heated from both sides, their heat fluxes are significantly higher than wall values. If a CFB must meet some very unusual operating requirements, i.e., capability for stand alone firing a wide range of liquid fuels (oil, desaphalting tar, bitumen, etc.) or gaseous fuels (natural or synthetic gas), then the normal rifling may be added to the furnace enclosure walls.

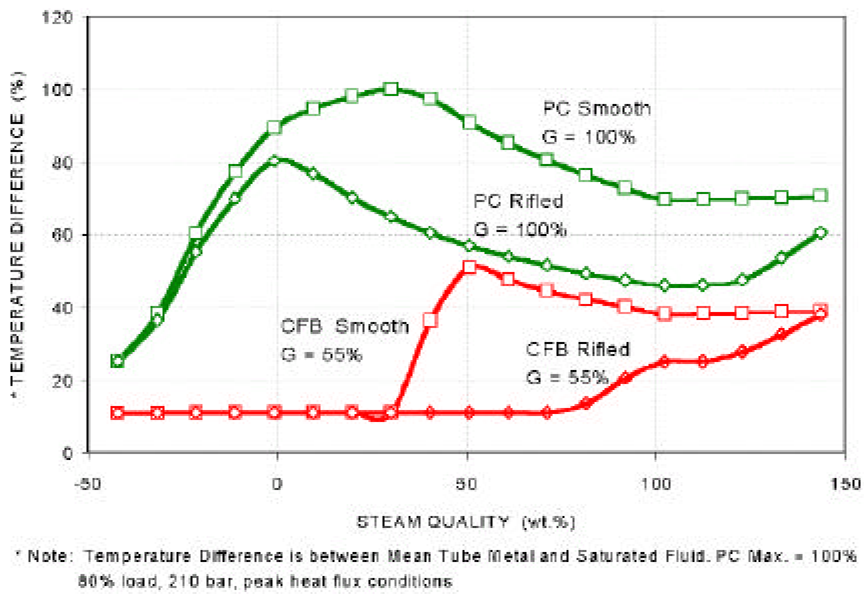


Figure 1.4.3 DNB Near Critical Pressure

1.5 Typical CFB Boiler Design Features

A CFB boiler is formed, for the most part, from the cooled membrane walls shown in Figure 1.3.9 and named Monowall^{TM} construction. With combustion occurring in the furnace section where heat release/wall heat absorption rates are at a maximum, the furnace membrane walls are cooled with water and serve as evaporator tube surface. The front and back walls of the furnace slope inward at the base of the unit to reduce the cross sectional flow area in the region of air injection. Combustion air (primary air) enters at the base and the reduced cross section results in increased gas/fluidizing velocities that enhance the mixing of bed materials. The primary air enters through Arrowhead Nozzles welded to a membrane wall floor called the air distributor plate. The nozzles are welded to the membrane fins between the water cooled tubes that form the floor/air distributor plate and the nozzle shape minimizes the back sifting of bed material into the primary air plenum when the unit is shut down, see Figures 1.5.1 through 1.5.3. Penetrations are provided in the sloping furnace walls to admit coal, see Figure 1.5.4, while other penetrations admit additional air (secondary air) to stage coal combustion for reduced NOx emissions. The lower portion of the furnace is lined with a thin layer of refractory to protect the walls from erosion as well as chemical attack from the substoichiometric conditions associated with staged combustion.

As unit sizes increase, the ratio of wall surface area to furnace volume decreases and additional evaporative surface must be placed inside the furnace. When these interior evaporator walls enter through openings provided in the furnace side walls as shown in Figure 1.5.5 they are called wing walls; when they enter through the air distributor plate as shown in Figure 1.5.6, they are called full height wing walls or division walls. In both cases they extend up to and exit through openings provided in the furnace roof. When provided, they are connected in parallel with the furnace walls in a single pass water flow arrangement.

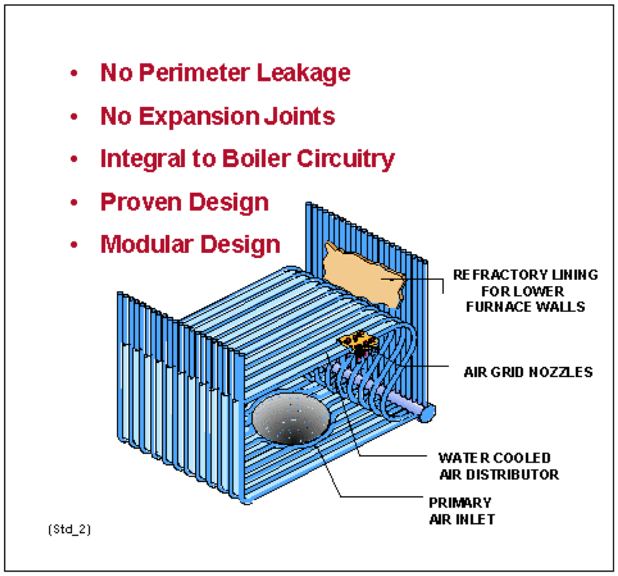


Figure 1.5.1 Water Cooled Air Distributor Plate for Primary Air Injection

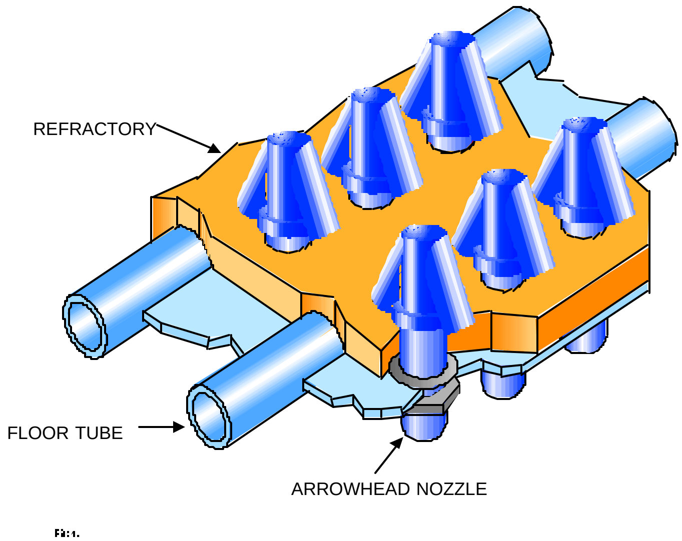


Figure 1.5.2 Arrow Head Nozzles for Primary Air Injection

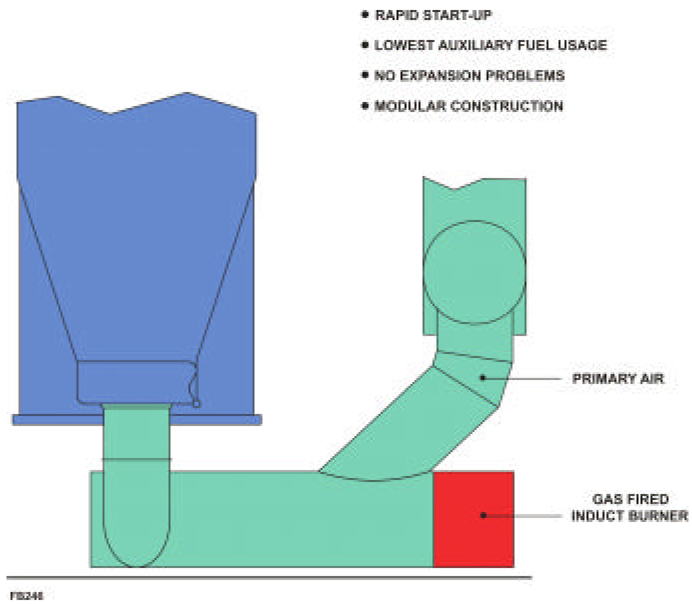


Figure 1.5.3 Primary Air Feed Duct and Start Up Burner

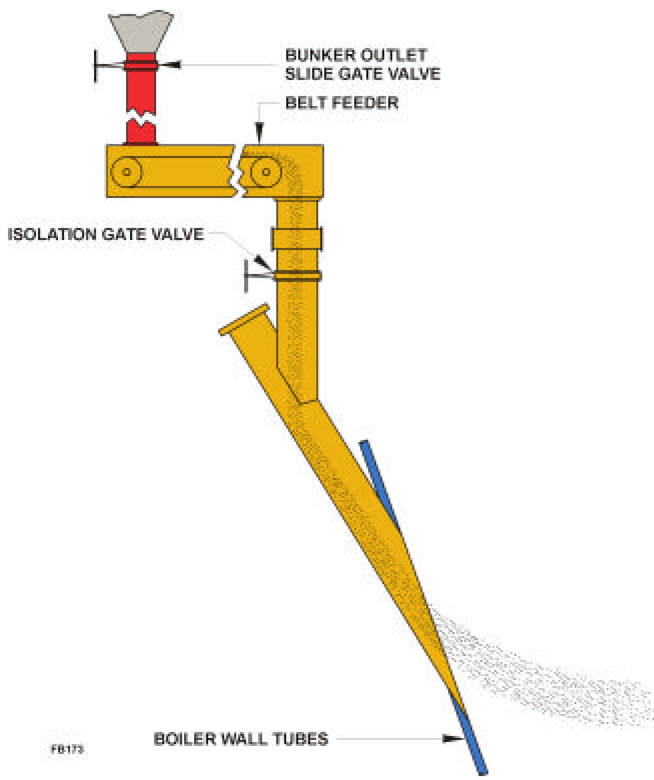


Figure 1.5.4 Typical Coal Feed Arrangement

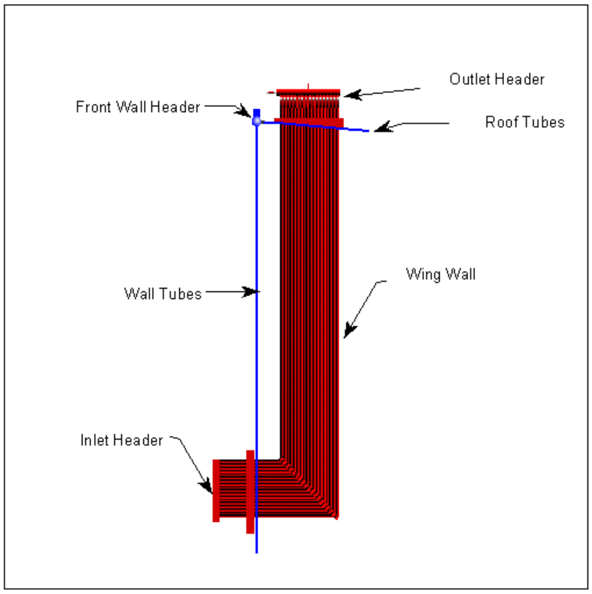


Figure 1.5.5 Typical Wing Wall Panel

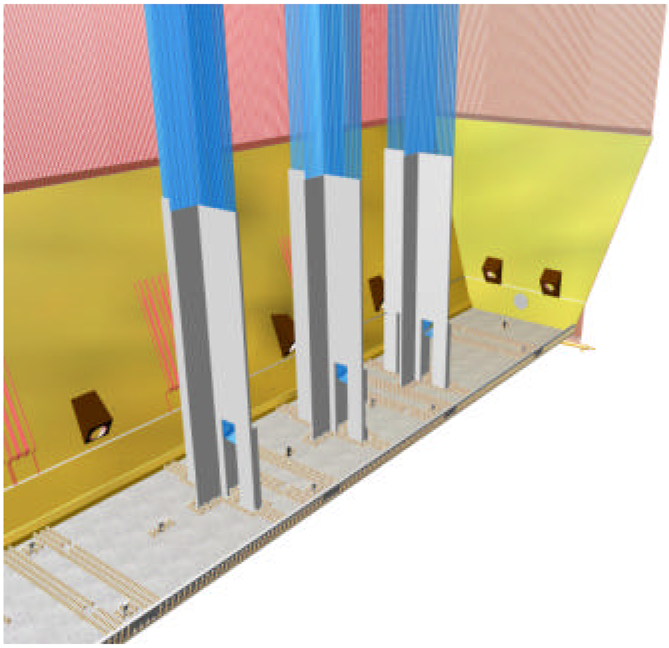


Figure 1.5.6 Typical Full Height Wing Wall Panels

Particulate entrained in the furnace flue gas are removed by solids separators located at the top of the unit. Although in early CFB boilers the solids separators took the form of cylindrical shaped units (cyclones), the separators are now formed from flat membrane wall panels that approximate a cyclone shape (see Figure 1.5.7) and are lined with a thin layer of abrasion-resistant refractory to protect against erosion. The design, which is a Foster Wheeler patented innovation, allows direct coupling to the furnace and provides the following major advantages:

- The flat Monowall® enclosure walls of the separators and their hopper bottoms are easy to fabricate with convectional fabricating techniques, are simple to top support with hangers, are lighter and easier to erect than a plate/refractory cyclone, and expand downward with the furnace.

- The use of Monowall® walls for the enclosure makes it very easy to integrate with the furnace and reduces the requirement for the high temperature refractory duct work and hot expansion joints used with plate/refractory type cyclones.

- The water cooled separator and hoppers require only about a one inch thick layer of refractory whereas plate/refractory type cyclones require 12 to 18 inches of refractory. This reduces cold start-up time, improves cycling, and reduces weight and maintenance costs.

- The outside of the water cooled separator is covered with insulation and lagging, so that the skin temperature is no different than the rest of the boiler. This significantly reduces radiant heat loss as compared to the plate/refractory design.

Particulate captured by the separators are returned to the base of the unit for injection back into the furnace. As units increase in size and move to more advanced steam conditions, there is a need to pack more and more heat transfer surface into the CFB boiler. One means for accommodating additional surface is to place fluidized bed heat exchangers in the solids return path at the base of the unit. Solids passing through these fluidized bed units transfer their heat to serpentine shaped tube bundles located in the beds (see Figure 1.5.8). The fluidized beds, named Integrated Recycle Heat Exchangers (INTREXs™), are an ideal location for high temperature superheat and reheat tube surfaces; the fine particles and low gas velocities employed in these bubbling beds provide bed to tube heat transfer coefficients that are much higher than convection path coefficients and they eliminate tube erosion risks. In addition to absorbing heat from the solids draining from the separators (called externally circulating INTREXs™), openings can be provided in the furnace walls to allow an additional in-flow of hot solids (called internal circulating INTREXs™); this supplemental flow enables high temperatures to be maintained even at part load when solids circulation rates are reduced. Solids are returned to the furnace from the INTREXs™ via air fluidized lift legs. By controlling the lift leg air flow rate/fluidizing velocity, the solids flow rate and heat absorbed by the INTREXs™ can be controlled. Rapid heat absorption control can also be provided by varying the fluidizing velocity in the INTREX™ beds. The INTREX™ enclosure walls are formed from cooled membrane walls and they allow them to grow downward with the furnace walls thereby eliminating the need for expansion joints.

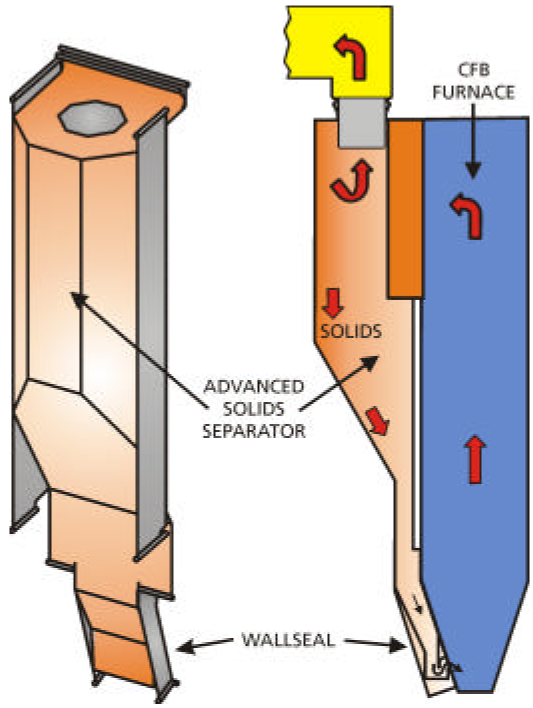


Figure 1.5.7 Compact Solids Separator

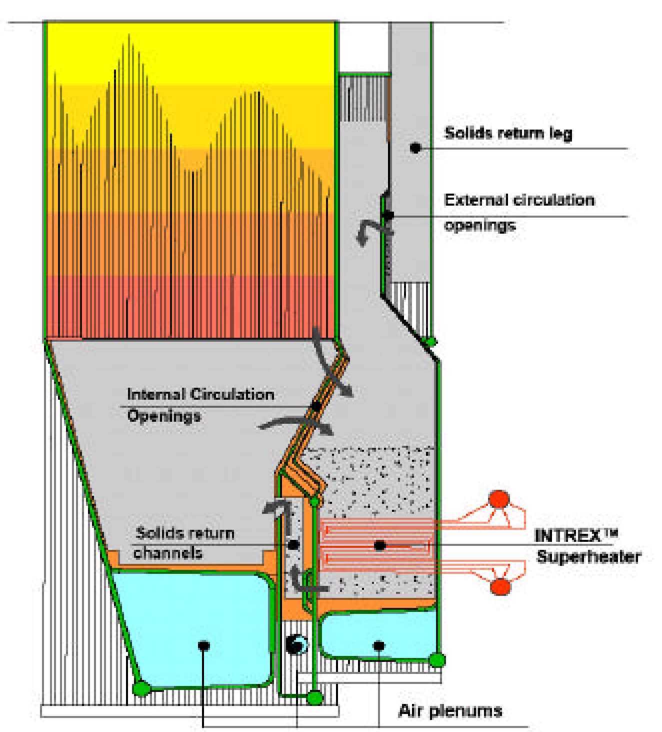


Figure 1.5.8 INTREX^{TM} Heat Exchanger

The flue gas from the solids separators discharge to a duct that connects to the convection path HRA. The HRA contains a series of serpentine shaped tube bundles which, through superheating, reheating, and feedwater preheating (economizer) functions, cool the flue gas for discharge to an air heater provided downstream of the boiler. Similar to large PC boilers, the HRA is typically divided into two parallel gas flow paths; as shown in Figure 1.5.9, one path contains reheat surface while the other contains superheat and, depending upon the design, some economizer surface. Dampers at the outlet of each gas path control the distribution of flue gas over the surfaces and they are operated to control the reheat temperature; water spray attemperators, in contrast, are used to control the superheat steam temperature. After passing through the dampers, the gas streams combine, pass over economizer surface, and discharge to the downstream air heater. The separator discharge duct, HRA enclosure walls, and HRA division wall are all formed from steam cooled membrane walls and the duct inside surfaces are protected from erosion by a thin layer of refractory. Soot blowers are provided in the HRA walls to keep the tube bundles free of ash. On smaller size boilers the parallel path gas flow arrangement may be replaced with a simple series flow arrangement of surfaces and steam recirculation used to control the reheat temperature.

Solids are drained continuously from the bottom of the furnace (bottom ash) to control the inventory of solids circulating in the unit. The solids are typically cooled to 500ºF by fluidized bed stripper coolers and then transported to bottom ash silos for disposal. As shown in Figures 1.5.10 through 1.5.12, each stripper cooler is divided into zones that are fluidized with combustion air. Solids draining from the furnace enter the first zone, which is designed to complete the combustion of any unburned carbon and blow the finer particles back into the furnace. From the first zone the solids continue through the next three zones two of which contain water cooled tube bundles; a rotary valve at the far end controls the bottom ash withdrawal rate. Water sprays are provided in the first three sections to guard against any high temperature upsets.

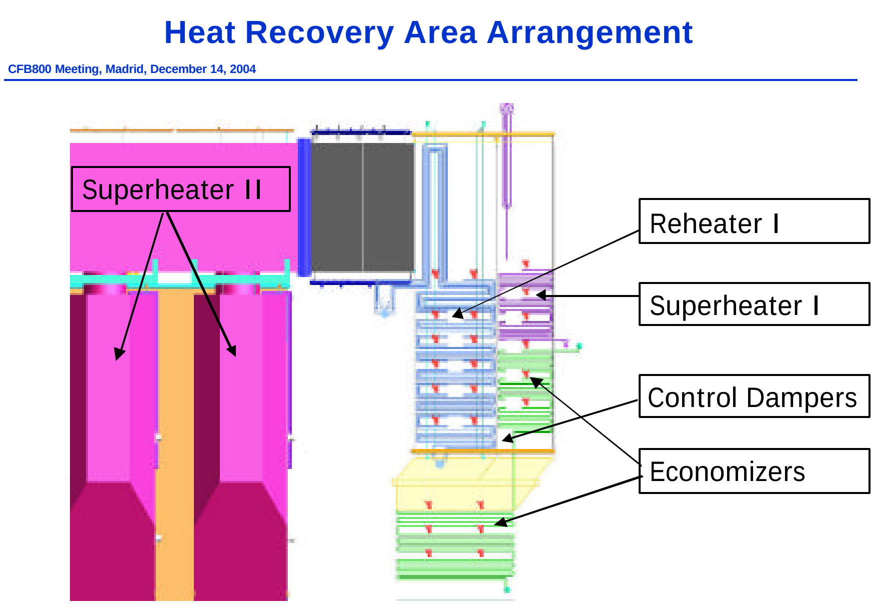


Figure 1.5.9 Parallel Gas Path HRA Arrangement

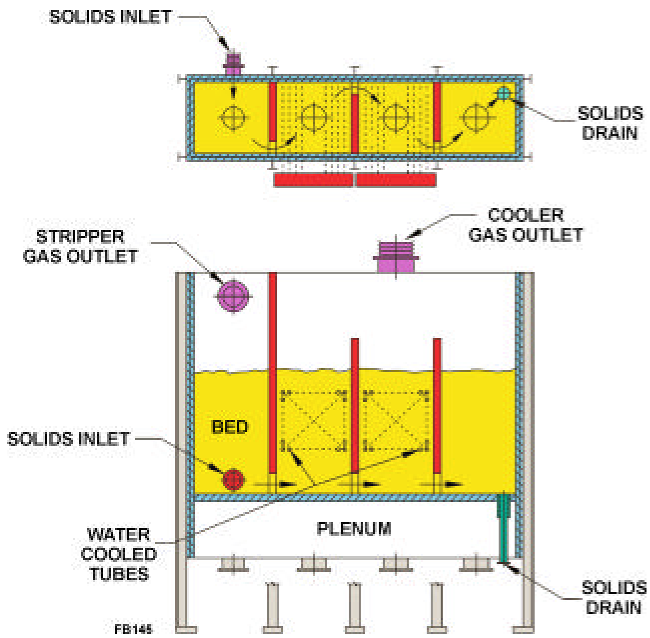


Figure 1.5.10 Stripper Cooler Sectional

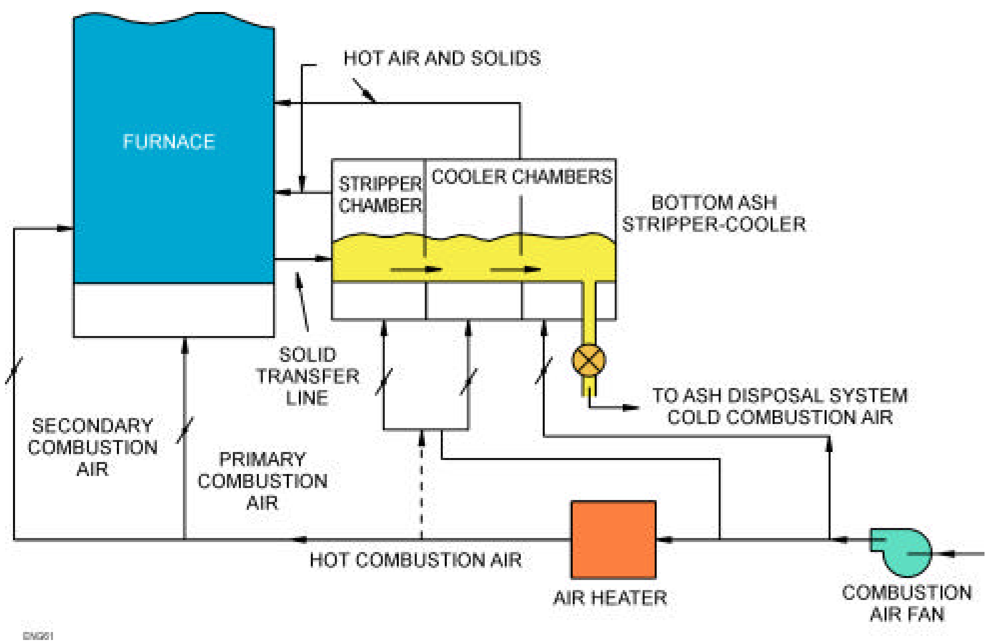


Figure 1.5.11 Stripper Cooler Air Flow Path

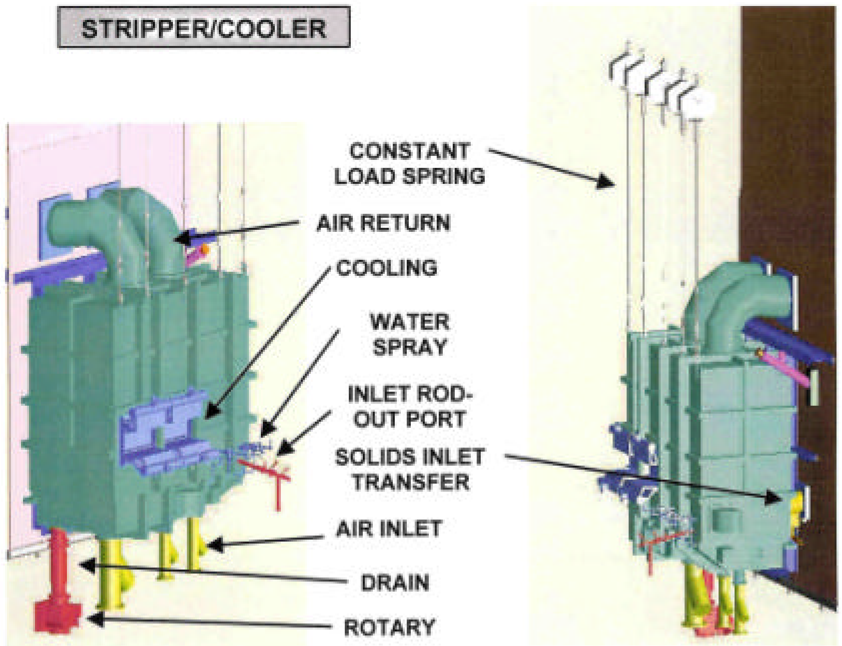


Figure 1.5.12 Stripper Cooler Arrangement

To achieve higher net plant efficiencies, supercritical boilers are being designed for higher main steam temperatures and higher feedwater inlet temperatures. When configuring the boiler, the designer must consider the following:

Economizer. The size of the economizer must be balanced between being large enough to lower the flue gas temperature for a practical air heater size and yet small enough to prevent steaming from occurring during variable pressure, part load operation. As steam parameters are increased, this task becomes more difficult. Special features such as a flue gas bypass around the economizer and/or limiting the variable pressure ramp (raising the minimum pressure) must be considered to prevent steaming from occurring.

Evaporator. The furnace internal height must accommodate the combined height of the solids separator and the pressure sealing device that facilitates the return of solids back either to the furnace or to INTREX™ heat exchangers. In addition, the height must provide sufficient residence time for the completion of combustion and emission control reactions while providing sufficient heat transfer surface to achieve the required evaporator duty over the operating load range. As load is reduced, the steam leaving the furnace enclosure walls must be sufficiently superheated so that wet steam does not pass through the in-line steam/water separators, as the latter are only meant to collect water during start-up when the boiler is controlled similar to a drum type boiler. Options other than raising the furnace height include:

- Internal Furnace Heat Transfer Surface. Internal, full-height, evaporator tube panels can be installed within the furnace so that the furnace height can be minimized. The diameter and spacing of the panel tubes, however, must be carefully selected so that their thermal/hydraulic performance is similar to the furnace enclosure tubes thereby ensuring equal exiting steam temperatures.

- INTREX™ Heat Exchanger Solids Bypass. An operational adjustment that can be made to ensure a sufficient level of superheat leaving the furnace walls is to bypass solids around the INTREX™ superheaters; this will raise the temperature of the solids returning to the furnace and, hence, the furnace temperature for increased heat transfer to the walls. Solids are returned to the furnace via liftlegs and, by increasing the liftleg aeration rates, the solids return/bypass rates can be increased. (see Figure 1.5.8).

Superheater. There are several options for locating superheater heat transfer surface in a CFB boiler; they include wing walls or Omega panels within the furnace, convection tube bundles in the HRA, and/or tube bundles within INTREX™ heat exchangers. As steam temperatures are pushed to higher levels, there are limitations on where the finishing superheater (FSH) can be located. For example, if the FSH is located in the HRA, it will become difficult to maintain both full main and full reheat steam temperature over the load range for extended steam turbine life, e.g., as load is markedly reduced the furnace exit temperature will decrease and the flue gas temperature will approach the required steam temperature.

Although the furnace exit gas temperature will decrease at part load, the temperature in the lower portion of the furnace will experience a much smaller temperature decrease. With the steam flow rate reduced at part load, the steam temperature in intermediate superheat wing walls located in the lower portion of the furnace will rise. Walls fabricated from T91 tube material have a temperature limit of about 1150ºF. Beyond this temperature, the material would have to be upgraded to stainless steels that require expensive post weld heat treatment. As a result, it is better to locate the high temperature FSH in the furnace wing walls positioned higher up in the furnace so that they would not experience a part load, high metal temperature condition. However, the panels would still be limited to the requirements for T91 material.

The best location for the finishing superheater (FSH) is within the INTREX™ heat exchangers. The serpentine tube coils can be fabricated from stainless or other high grade materials without fabrication limitations. Here, the fine particle size of the bubbling fluidized bed provides high heat transfer coefficients that minimize the amount of heat transfer surface required. In addition, the circulating solids are hot enough/have a sufficiently high temperature head to achieve the levels of superheat temperature required for the most advanced supercritical steam cycles. At part load, the solids can also be bypassed around the superheater, if necessary to keep tube metal temperatures under control.

Reheater. For locating the reheater, the same options apply as noted for the superheater. However, special consideration must be given to minimize pressure loss and provide sufficient tube cooling. To limit pressure loss, lower mass flux rates are typically used that result in low steam side film heat transfer coefficients. In addition, the reheater's lower operating pressure results in steam side film properties that also reduce the heat transfer coefficient. Consideration must also be given to the method for reheat steam temperature control. Options include a parallel pass HRA with gas flow proportioning, a series pass HRA with a reheat steam bypass, or location within the INTREX™ heat exchanger using solids bypass and/or varying the fluidizing velocity. Project specific requirements will dictate where best to locate the reheater and the most responsive method for temperature control.

2.0 Executive Summary

Electric utility interest in supercritical pressure steam cycles is returning in the US after waning in the 1980s. With typical steam turbine throttle condition of ~3500 psig and 1000ºF, these cycles offer higher plant efficiencies than subcritical pressure plants, along with a proportional reduction in both traditional stack gas pollutants and CO_2 release rates. In addition, the desire for even higher efficiencies has sparked interest in ultra supercritical (steam temperatures typically 1100ºF and higher) and advanced ultra supercritical (steam conditions approaching 5000 psig and 1300ºF) steam cycles. The advantages of supercritical (SC) and ultra supercritical (USC) pressure steam conditions have been demonstrated in the high gas temperature, high heat flux environment of pulverized coal-fired boilers. For economies of scale these units are large in size and are frequently in the 800 to 1000 MWe range.

Circulating fluidized bed (CFB) boilers were first introduced in the 1970s and are an alternative to pulverized coal-fired (PC) boilers. Exhibiting multi-fuel and low grade fuel capabilities, low emissions, operating flexibility, and high reliability, they have steadily increased in size and, as of the writing of this report, the largest units in operation are the two 300 MWe, natural circulation, CFB boilers supplied by Foster Wheeler to the Jacksonville Electric Authority. Since CFB boilers operate with combustion temperatures and in sizes that are much lower/smaller than those of PC boilers (~1600ºF versus 3500ºF and ~300 MWe versus 1000 MWe), the ability of CFB boilers to accommodate SC, USC, and advanced USC has been questioned. To address this, a study was conducted to develop conceptual designs and cost estimates of USC CFB boilers.

Reference [4-1] presented a conceptual design and determined the economics of a USC PC plant operating with 4500psig/1100ºF/1100ºF/1100ºF (double reheat) steam turbine conditions; the plant had a net power output of 399.7 MWe and a higher heating value (HHV) efficiency of 41.4 percent. To permit a consistent comparison of technologies, the USC CFB study was conducted for the same site conditions, the same SO_2 and NOx lb/MMBtu emission rates, and included a study case with the same steam conditions and output. In addition to that 400 MWe double reheat case, the CFB study also studied single reheat in nominal 400 MWe and 800 MWe plant sizes. Assuming tubing and piping materials could be developed that would result in component thicknesses that would be similar to those of USC boilers, a nominal 800 MWe CFB design was developed for advanced USC steam conditions.

The move to 400 and 800 MWe supercritical CFB boilers represents a significant design change and scale-up. Items to be considered in such a scale-up are the design of:

1.) the furnace/riser where combustion occurs
2.) the solids separators that remove entrained particulate from the combustion exhaust
3.) the gas heat recovery area (HRA) that cools the combustion gas exiting the separators
4.) the fluidized bed heat exchangers that cool the particulate collected by the separators for return to the base of the furnace

5.) the overall integration of the CFB boiler steam-water circuitry with the HRA and furnace hot circulating loop of solids.

Plant heat and material balances were prepared for each of the study cases and conceptual designs were developed for three different CFB boilers. The CFB conceptual designs addressed each of the above concerns and, with their designs reflecting conventional design practices, an R&D development effort will not be required to support their construction. Where applicable, balance of plant equipment was sized, components were cost estimated, and overall plant performance and economics were determined.

Table 2.1 summaries the results of the study. The efficiencies of the nominal 400 MWe double reheat USC CFB plant (Case 1B) and the USC PC plant [4-1] were found to be comparable (41.2 versus 41.4 percent). Since [6-1] has shown double reheat to be one of the most expensive ways to increase plant efficiency, and since the CFB plant showed only a 0.6 percentage point efficiency gain through it, the economics of the double reheat case were not determined.

Table 2.1 USC CFB Boiler Plant Performance and Economics

Case	-------------Steam Turbine Conditions------- Throttle Press psig	Sht Temp F	Rht Temp F	Gross Power MWe	Auxiliary Power* MWe	Net Plant Output MWe	HHV Efficiency %	Total Plant Costs** $/KW	Cost of Electricity $/MWhr	% Efficiency Emission Reduction***
1A	4500	1100	1100	426.3	21.4	404.9	40.6	1,551	52.21	8.8
1B	4500	1100	1100/1100	425.8	23.4	402.4	41.2			10.2
2	4336	1112	1148	777.6	37.2	740.5	41.3	1,244	44.08	10.4
3	5061	1292	1328	804.6	36.4	768.2	43.3			14.5

*Boiler feed pump has steam turbine drive
**January 2006 dollars
***Compared to a plant with 37% efficiency and the same net output and lb/MMBtu emission rate

The nominal 400 MWe (Case 1A) and 800 MWe single reheat (Case 2), USC plants had net outputs of 405 MWe and 741 MWe. Their total plant costs were $1,551/kW and $1,244/kW and their 20 year levelized costs of electricity were $52.21/MWhr and $44.08/MWhr respectively; as discussed in Sections 5.4 and 7.5, these costs are expected to be similar to those of comparable USC PC plants.

The single reheat USC CFB plants possessed efficiencies of 40.6 and 41.3 percent, respectively, and, moving the latter to advanced USC conditions, increased its plant efficiency to 43.3 percent. Compared with a new subcritical pressure plant, which typically operates with about a 37 percent efficiency, the supercritical conditions will reduce plant coal and ash flow rates, stack gas emissions, and CO_2 release rates by approximately 9 to 15 percent.

Additional findings of the study are:

1.) Since CFB furnace heat fluxes are lower and more uniform than PC boilers:

   a. CFB furnace enclosure walls can be constructed from straight, self supporting, vertical tubes rather than the complex spiral wound tube designs of PC boilers that require a special support system.
   b. CFB furnace walls can operate at water mass flow rates much lower than a PC boiler without the need for internal rifling and still be protected from DNB.
   c. With smooth tubes and lower water mass flow rates being used, CFB furnace wall frictional pressure losses are lower than hydrostatic pressure losses and unlike USC PC boilers:
      i. USC CFB boilers will require less boiler feed pump power.
      ii. CFB furnace walls will operate with a self compensating, natural circulation characteristic wherein an excessively heated tube will experience an increase in water flow that will minimize the tube-to-tube temperature differences that could lead to tube failures.

2.) With CFB furnace heights and depths limited to approximately 165 and 40 feet from the standpoint of heat transfer effectiveness and the ability to distribute fuel and secondary air across the furnace cross section, the move to larger capacities will be essentially achieved by modular type width increases:

   a. Large CFB boilers will be constructed from nominal 100 MWe type building block modules, each consisting of a section of furnace section linked to two solids separators placed side by side and then opposite each other to reach 400 and 800 MWe sizes.

3.) Including coal and limestone feed silos, air fans, and air heater, a 400 MWe USC CFB boiler will occupy a foot print approximately 180 feet by 275 feet and be supported by structural steel approximately 225 feet above grade. The comparable dimensions of the nominal 800 MWe units are 200 by 300 by 250 feet.

4.) Computer model simulations of the 400 MWe and 800 MWe units have predicted furnace heat release patterns, heat flux profiles, pressure profiles, oxygen profiles, and maximum tube wall temperatures that are consistent with Foster Wheeler CFB boiler design standards.

6.) Part load analyses have shown that superheat and reheat steam temperatures can be maintained at full load values over the 40 to 100 percent load range, whereas, 50 to 100 percent is typical of PC boilers.

7.) Despite the CFB's relatively low ~1600ºF combustion temperature, the 1300ºF steam temperature of advanced USC cycles can be accommodated by operating Foster Wheeler's INTREX fluidized bed heat exchangers with patented internal solids circulation.

8.) The physical arrangements of the 400 MWe and 800 MWe USC units reflect conventional Foster Wheeler CFB boiler configurations and can be deployed without the need for R&D development work.

9.) The physical arrangement of the 800 MWe CFB boiler operating with advanced USC steam conditions also reflects conventional Foster Wheeler CFB design practices but will require the development of new tube/pipe materials.

10.) The efficiencies and economics of 400 MWe and 800 MWe USC CFB and PC boiler plants are expected to be comparable.

11.) Use of advanced USC conditions (nominally 5061psig/1300ºF/1300ºF) will increase the efficiency of the 800 MWe CFB plant to 43.3 percent

In summary, this study has shown that the move to 400 MWe and 800 MWe size USC CFB boilers is technically feasible, economically viable, and will involve minimal scale-up risk. In addition, the higher plant efficiencies that supercritical conditions provide will enable the plant to operate with less fuel consumption and a proportional reduction in waste ash flow rates, traditional stack gas pollutants, and CO_2 release rates; depending upon the supercritical conditions selected, the fuel and emission rates will be approximately 9 to 15 percent lower than a new, subcritical pressure plant operating with 37 percent efficiency. Hence, supercritical CFB boilers will be a viable means for meeting the present and future economic and environmental needs of the US electric utility industry.

3.0 Proposed Program / Economic and Costing Methodology

3.1 General Approach

The cost and economics of the USC CFB plants presented in later sections were determined by Foster Wheeler's CFB State of the Art Power Plant (SOAPP) Program. The CFB SOAPP Plant Evaluation Program is a software product that was developed by Foster Wheeler and the Electric Power Research Institute (EPRI). Foster Wheeler Power Group developed the boiler programming and provided tailored collaboration funding and technical support for development of the balance of the plant. At present, the working spreadsheet version is available only to Foster Wheeler and EPRI. Foster Wheeler has customized this version for its own use, incorporating many of its design standards and revising the program output for presentation to prospective customers.

The CFB SOAPP Plant Evaluation Program is a software tool used to evaluate both circulating fluidized bed boiler and balance of plant design alternatives as well as assess their impact on overall plant performance and economics. Although the program has the ability to calculate for specific project site conditions CFB plant performance (including boiler efficiency, turbine heat rate, fuel and sorbent consumption, water consumption, and emissions), its standard design algorithms can be bypassed to allow more advanced/customized designs to be utilized. With the USC operating conditions of this study being non standard, the SOAPP customized design options were utilized e.g. ASPEN simulations were generated to establish operating conditions for each advanced plant configuration and a CFB boiler design complete with auxiliaries was developed and cost estimated for each case. With that specialized data input, the program was used to complete the sizing and cost estimating of balance of plant equipment including:

<u>Fuel Preparation and Handling Systems</u>
Mills/crushers
Fuel storage and handling
Conveying

<u>Sorbent Preparation and Handling Systems</u>
Mills/crushers
Storage and handling
Conveying
Drying

<u>Inert Systems</u>
Storage and handling

<u>Ash Handling</u>
Ash conveying from boiler (bottom ash)
Ash conveying from boiler (economizer/air heater ash)
Ash conveying from ESP/baghouse
Ash conditioning
Ash storage

<u>Water Treatment</u>
Cycle chemistry
Makeup demineralizer
Demineralized and raw water tanks
Waste water treatment

<u>Stack</u>
Stack sizing and number of flues
Stack materials

<u>Turbine Cycle</u>
Steam turbine-generator
Condensate pump
Feedwater heaters
Boiler feed pump

<u>Heat Rejection Systems</u>
Condenser
Once-through systems
Mechanical draft cooling towers
Circulating water pumps

Service water pumps
Closed cooling water system

SCR (when applicable)
Anhydrous ammonia
Aqueous ammonia

Electrical Systems
Transformer/bus ducts
Switchgear
Switchyard
Cables/wiring

Civil / Structural
Overall plant dimensions and arrangement
Boiler building structure
Turbine building structure
Miscellaneous structures
Foundations
Wind load adjustment factors
Seismic zone adjustment factors

Plant Control Systems
Distributed control system
Local control systems

Ancillary Systems
Continuous Emission Monitoring (CEM)
Instrumentation
Plant and instrument air systems

Installation costs for the above were also calculated by the program using labor conditions specified for the study site.

Economic Analysis

The preceding calculated design and performance values provide relationships for calculating capital, operating and maintenance (O&M), financial, and other economic parameters. The financial feature of the program was used to determine overall plant costs and economics and yield a levelized cost of electricity (COE).

The program calculated the following costs in order to construct the pro forma:

Total Capital Requirements
Equipment
Bulk materials and labor

Engineering and home office labor
Contingency
Start-up
Working capital
Land
Interest during construction
Other financing costs
Debt service reserve

O&M and Production Costs
Fixed O&M
Plant Staff
Normal Maintenance
Replacement reserve
Insurance
Miscellaneous
Variable O&M
Limestone
Ash
Water & treatment
Ammonia
Fuel cost

Financial Pro-Forma

A Financial pro-forma can be generated by the program for both Independent Power Producer and Investor Owned Utility (IOU) calculations based on the above cost and technical data, as well as user input economic parameters; IOU calculations were the basis for this study.

The following cost elements are included in the program's financial output based on an IOU financing approach:

- Book depreciation
- Deferred income tax
- Normalization of investment tax credit
- Interest expense
- State and Federal income taxes
- Recovery of preferred stock, including AFUDC
- Recovery of common equity, including AFUDC
- Total capital recovery
- Return on equity

The program uses the following in determining project rates of return (IRR) and debt coverage ratios for IOU projects

- Tax depreciation (MACRS), depends on fuel type

- Interest expense, up to 3 loans
- Principal payment
- State and Federal income taxes
- Interest during construction
- Commitment fees
- Debt service reserve
- Closing costs
- Carry forward tax losses (optional)

3.2 Economic Factors

The cost and economic assumptions used in this study are given in Tables 3.2.1 and 3.2.2.

3.3 Cost Estimate Basis and Assumptions

The general estimate basis and assumptions are identified below:

- Total plant costs are expressed in January 2006 dollars.

- The estimate represents a mature technology plant, or "nth plant" (i.e., it does not include costs associated with a first-of-a-kind plant).

- The estimate represents a complete plant facility.

- The estimate boundary limit is defined as the total plant facility within the "fence line"; it begins at the rail road tracks entering the plant and terminates at the high side of the main power transformers. River water is assumed to be available for cooling tower and demineralizer make up and is reasonably proximate to the site.

- Site location is within the Ohio River Valley, southwestern Pennsylvania/eastern Ohio, but not specifically sited within the region.

- Terms used in connection with the estimate are consistent with the EPRI Technical Assessment Guidelines (TAG) [3-1].

- Costs are grouped for the most part according to a process/system-oriented code of accounts; all reasonably allocable components of a system or process are included in the specific system account in contrast to a facility, area, or commodity account structure.

- Design engineering services, including construction management and contingencies are expressed as a percentage of equipment costs delivered and erected at the job site.

- The fuel cost was developed on the basis of a straightforward calculation involving the plant size, plant heat rate, coal higher heating value, coal unit cost, plant annual operating hours, and a levelizing factor.

Table 3.2.1 Unit Costs and Escalation

	Year 2006	Inflation Rate*
Feed Costs		
Coal, $/MMBtu	1.34	2.50%
Limestone, $/ton	15.00	2.50%
Water Treatment Chemicals, $/kgal	0.50	2.50%
Waste Disposal Costs		
Fly Ash/Bottom Ash Disposal, $/ton	10.00	2.50%
Other Costs		
Plant Operating Labor, $/hr	33.00	2.50%
Plant Land, $/acre	1500.00	2.50%

- The operating and maintenance expenses and consumables costs were developed on a quantitative basis.
  - The operating cost is determined on the basis of the number of operators required.
  - The maintenance cost is evaluated on the basis of relationships of maintenance cost to initial capital cost.
  - The cost of consumables is determined on the basis of individual rates of consumption, the unit cost of each consumable, and the plant annual operating hours.

Table 3.2.2 Financial Assumptions

General Data			
Levelized Capacity Factor:	85	%	
Capital Cost Year Dollars:	2006	January	
Time to Design and Construct Plant:	40	months	44*
Plant Startup Date:	2009	May	September*
Plant Land Area	100	acres	
Financial Criteria			
Project Book Life:	20	years	
Book Salvage Value:	0.0	%	
Project Tax Life:	20	years	
Tax Depreciation Method:	Accel. Based of MACRS Class		
Property Tax Rate:	1.0	% per year	
Insurance Tax Rate:	1.0	% per year	
Federal Income Tax Rate:	35.0	%	
State Income Tax Rate:	6.0	%	
Investment Tax Credit/% Eligible	0.0	%	
Economic Basis:	Constant Dollars		
Capital Structure	% of Total		Cost (%)
Common Equity	20		12.0
Tax Free Municipal Bond Debt	80		6.5
Weighted Cost of Capital:(after tax)		5.57%	
Escalation Rates			
	2.5	% per year	
	2.5	% per year	

* 740.5 MWe plant requires 44 month schedule with September 2009 startup

Each of these expenses and costs is determined on a first-year basis and levelized at the 20-year life of the plant through application of a levelizing factor to determine the electricity production cost.

3.4 Cost Elements

3.4.1 Capital Costs

The capital cost, specifically referred to as total capital requirement (TCR) for the mature USC power plant, was estimated using the EPRI methodology identified in Figure 3.4.1.1. The major components of TCR consist of bare erected cost, total plant cost (TPC), total plant investment (TPI), and owner's costs.

The capital cost was determined through the process of estimating the cost of major equipment items, components, and bulk quantities identified. A Code of Accounts was developed to provide the required structure for the estimate. The Code facilitates the consistent allocation of individual costs and provides recognition of battery limits and the scope included in each account.

3.4.2 Bare Erected Cost

The bare erected cost level of the estimate, also referred to as the sum of process capital and general facilities capital, consists of the cost of factory equipment, field materials and supplies, direct labor, indirect field labor, and indirect construction costs.

3.4.3 Total Plant Cost (TPC)

The TPC level of the estimate consists of the bare erected cost plus engineering and contingencies.

Engineering costs represent the cost of architect/engineer services for design/drafting, project construction management services, and fee and were set at 10 percent of the bare erected cost. The cost for engineering services provided by the equipment manufacturers and vendors is included directly in the equipment costs.

Allowances for process and project contingencies are also part of the TPC. Since the plant cost estimate assumes a mature technology, the process contingency was zero but a project contingency equal to 10 percent of the sum of bare erected and engineering costs was included.

3.4.4 Total Plant Investment (TPI)

The TPI at date of start-up includes escalation of construction costs and allowance for funds used during construction (AFUDC). AFUDC includes interest during construction as well as a similar concept for timing of equity funds over the construction period. TPI is computed from the TPC based on a linear drawdown schedule and the compounded interest (or implied equity rate) in the percentages of debt and equity. Drawdown was over the assumed 40 month construction schedule for the 405 MW plant, and 44 months for the 740 MW plant. As the analysis is done in constant 2006 dollars, no escalation was applied. The full AFUDC is used in calculating returns on debt and equity, but only the interest during construction is included in the depreciation base.

3.4.5 Total Capital Requirement (TCR)

The TCR includes all capital necessary to complete the entire project. TCR consists of TPI, prepaid royalties, pre-production (or start-up) costs, inventory capital, initial chemical and catalyst charge, and land cost:

- Royalty Costs have been assumed to be zero, as none apply.
- Start-Up/Pre-Production Costs are intended to cover operator training, equipment checkout, extra maintenance, and use of fuel and other materials during plant start-up. They are estimated as follows:
  - hiring and phasing-in prior to and during start up of operating and maintenance labor, administrative and support labor, variable operating costs ramped up to full capacity (including fuel, chemicals, water, and other consumables and waste disposal charges. These variable costs are assumed to be compensated by electric energy payments during the start up period.
  - costs of spare parts usage, and expected changes and modifications to equipment that may be needed to bring the plant up to full capacity.
- Inventory capital is the value of inventories of fuel, other consumables, and by-products, which are capitalized and included in the inventory capital account. The inventory capital is estimated as follows:
  - Fuel inventory is based on full-capacity operation for 30 days.
  - Inventory of other consumables (excluding water) is normally based on full-capacity operation for the same number of days as specified for the fuel.
  - ½ percent of the TPC equipment cost is included for spare parts.
- Initial catalyst and chemical charge covers the initial cost of any catalyst or chemicals that are contained in the process equipment (but not in storage, which is covered in inventory capital). No value is shown because costs are assumed to have been included in the component equipment capital cost.
- Land cost is based on 100 acres of land at $1,500 per acre.

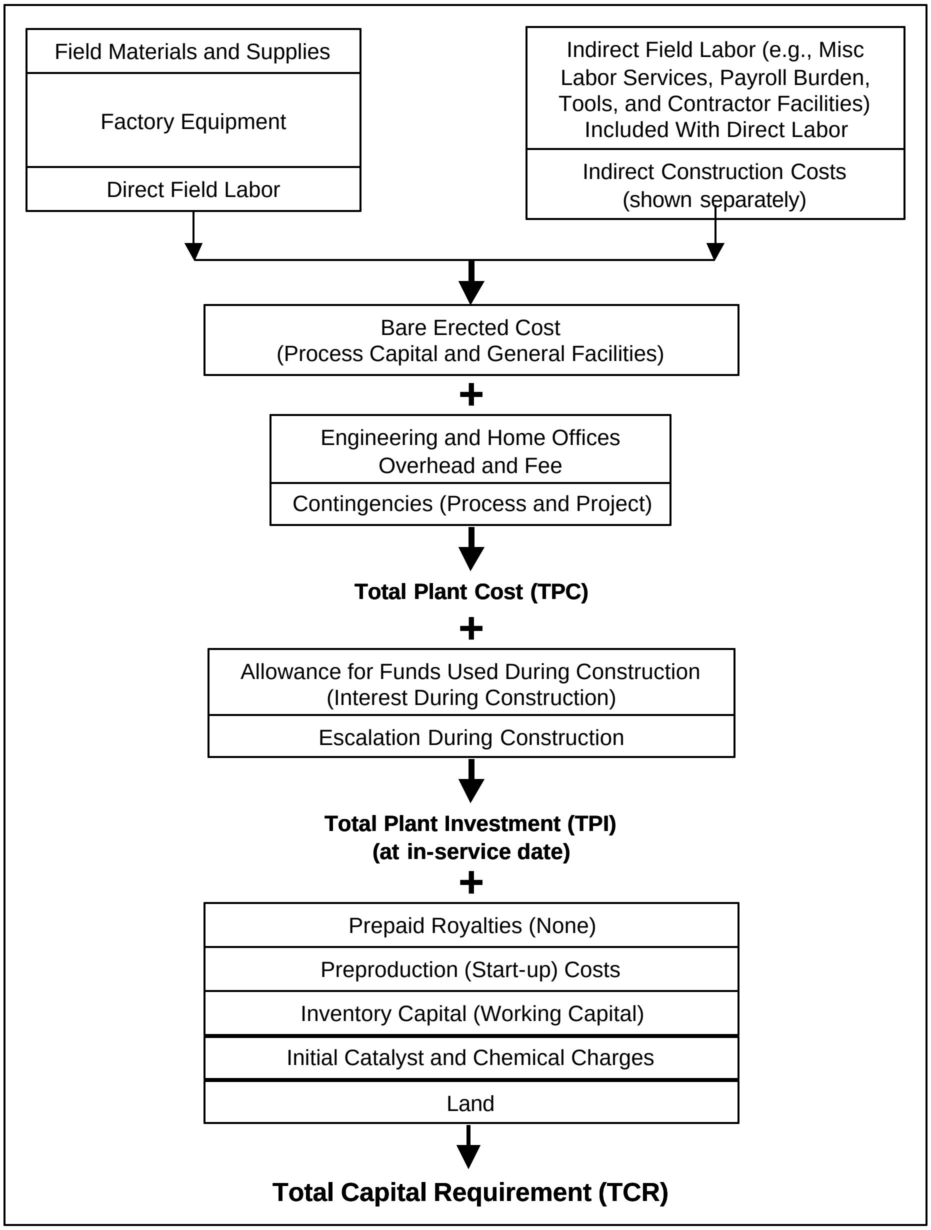


Figure 3.4.1.1 Components of Capital Cost

3.4.6 Capital Cost Estimate Exclusions

Although the estimate is intended to represent a complete plant, there remain several qualifications/exclusions as follows:

- Sales tax is not included (considered to be exempt).
- On-site fuel transportation equipment is not included (i.e., yard locomotive, bulldozers, etc.).
- Allowances for unusual site conditions, such as piling, extensive site access, excessive dewatering, extensive inclement weather, are not included.

- Switchyard (transmission plant) is not included. The cost scope terminates at the high side of the main power transformer.
- Ash disposal facility is excluded; only 3-day ash/slag storage silos have been provided (the ash disposal cost is accounted for in the ash disposal charge as part of consumables costs).
- Royalties.

3.4.7 Operating and Maintenance (O&M) Costs

The costs and expenses associated with operating and maintaining the plant include:

- Operating labor
- Maintenance
  - Material
  - Labor
- Administrative and support labor

The cost of operating labor was based on an estimate of the staffing needed to operate the plant whereas the annual maintenance costs were taken as a percentage of TPC.

The operating labor, maintenance material and labor, and other labor-related costs are combined to give a total operating and maintenance cost which is then divided into two components: 90 percent for fixed O&M, which is independent of operation, and 10 percent for variable O&M, which is proportional to operation. The first-year costs are in January 2006 dollars with an 85 percent capacity factor and assume normal operation. These O&M costs do not include the initial start-up costs, which are computed separately. A 20-year levelizing factor is applied to the first-year costs and expenses to arrive at appropriate values that contribute to the cost of electricity.

The other operating costs, consumables and fuel, are determined on a daily 100 percent operating capacity basis and adjusted to an annual plant operation basis, equivalent to operating at 100 percent load for 85 percent of the year (plant capacity factor).

The development of the actual values was consistent with TAG.

3.4.8 Consumable Costs

Costs included in this category are listed in Table 3.4.8.1 and include**:**

- Consumables
- By-product credit (if applicable)
- Auxiliary fuel cost (start-up fuel)

Feedstock and disposal costs are those consumable expenses associated with normal plant operation. Consumable operating costs are developed on a first-year basis and subsequently levelized over a 20-year period. The consumables category consists of water, chemicals, other consumables, and waste disposal.

The "water" component pertains to the acquisition charge for the water required for the plant steam cycle, cooling towers, miscellaneous services, and ash pug mills; treatment includes the cost of chemicals for water conditioning.

The "other consumables" component consists primarily of start-up fuel. The fuel quantity accounts for start-up heaters and miscellaneous users plus fuel for the auxiliary boiler.

The "waste disposal" component pertains to the cost allowance for off-site disposal of plant solid wastes. Although the ash from the CFB boiler can potentially be used for road construction, structural fill, agricultural fertilizing, etc., the economics of such uses would be highly site dependent. As a result, no credit was taken for the potential sale of CFB boiler ash.

Table 3.4.8.1 Consumable Unit Costs

	Unit Cost
Water per 1,000 gals	$1.00
Chemicals	
Water Treatment per kgal	$0.50
Limestone per Ton	$15.00
Other	
Supplemental Fuel per MMBtu	$6.00
Waste Disposal	
Fly Ash	$10.00
Bottom Ash	$10.00

3.4.9 Fuel Cost

The fuel cost is based on the plant full load coal flow rate with the plant operating 24 hours per day 365 days per year and an overall capacity factor of 85 percent. Coal costs are assumed to escalate at 2.5 percent per year from a year 2006 value of $1.34 per million Btu.

3.4.10 Total Production Cost

This is the sum of fixed O&M, variable O&M, fuel, and consumables costs less by-product credits. It is presented on both a present day (2006) and a levelized 20-year basis.

3.4.11 Carrying Charges

This is the sum of return on debt, 12 percent return on equity, federal and state income taxes, book depreciation, property taxes, and insurance. It is presented on a levelized 20-year basis.

3.4.12 Cost of Electricity (COE)

The revenue requirement method is widely used in the electric utility industry to perform an economic analysis of a prospective new power plant. This method permits the various dissimilar components of a new plant to be incorporated into a value that can be compared with various alternatives. From a cost of electricity standpoint the revenue requirement figure-of-merit is the levelized (over plant life) coal pile-to-buss bar cost of electricity expressed in \$/MWhr. The value, based on EPRI definitions and methodology, includes the TCR, which is represented in the levelized carrying charge (sometimes referred to as the fixed charges), 20-year levelized fixed and variable operating and maintenance costs, 20-year levelized consumables operating costs, and 20 year levelized fuel cost.

The levelized carrying charge, applied to TCR, establishes the required revenues to cover return on equity, interest on debt, depreciation, income tax, property tax, and insurance. Levelizing factors are applied to the first-year fuel, O&M, and consumables costs to yield 20-year levelized costs. A long-term inflation rate of 2.5 percent per year was assumed in estimating the cost of capital and in estimating the life-cycle revenue requirements for other expenses (includes coal escalated at 2.5 percent per year).

To represent these varying revenue requirements for fixed and variable costs, a "levelized" value was computed using the "present worth" concept of money based on the assumptions shown in Table 3.2.1 and 3.2.2. By combining costs and carrying charges, a levelized 20 year cost of producing electricity was calculated by the following:

Levelized COE* = (LCC+LFOM+LVOM+LCM–LLB+LFC) / MWhr of Electricity per Year

LCC	=	Levelized Carrying charge, \$/yr
LFOM	=	Levelized Fixed O&M, \$/yr
LVOM	=	Levelized Variable O&M, \$/yr
LCM	=	Levelized Consumables*, \$/yr
LBPC	=	Levelized By-product credit* (if any), \$/yr
LFC	=	Levelized Fuel costs*, \$/yr

* all for an 85 percent plant capacity factor

4.0 Experimental / General Basis for USC CFB Design Study

To allow a consistent comparison of technologies the site conditions used for the USC CFB based plants were the same as those used in [4-1].

4.1 Plant Site Conditions

The CFB plants assume a common generic site with conditions representing a typical Ohio River Valley site. Table 4.1.1 lists the characteristics of this site.

Table 4.1.1 Site Characteristics

Topography	Level
Elevation	500 feet
Design Air Pressure	14.4 psia
Design Temperature, Dry Bulb	63°F
Design Temperature, Wet Bulb	54°F
Relative Humidity	55%
Transportation	Rail access
Water	Municipal
Ash Disposal	Off site

The site consists of approximately 100 usable acres (excluding ash disposal area) located within 15 miles of a medium-sized metropolitan area that has a well-established infrastructure capable of supporting the required construction work force. The site is served by a river with sufficient capacity for meeting the plant's needs for make-up cooling water with minimal pretreatment and for the receipt of cooling system blow-down discharges. A railroad line suitable for unit coal trains passes within 2-1/2 miles of the site boundary.

4.2 Coal and Limestone

The plants utilize Illinois No. 6 coal from the Old Ben No. 26 Mine; the coal is delivered by unit train and possesses the Table 4.2.1 analysis. Greer limestone, with the analysis presented in Table 4.2.2, is also delivered by rail and is fed to the CFB boiler for SO_2 control.

Table 4.2.1 Illinois No 6 Coal Analysis

Proximate Analysis	**As-Received (wt%)**
Moisture	11.12
Ash	9.70
Volatile Matter	34.99
Fixed Carbon	44.19
TOTAL	100.00
HHV (Btu/lb)	11,666
Ultimate Analysis	**As-Received (wt%)**
Moisture	11.12
Carbon	63.75
Hydrogen	4.50
Nitrogen	1.25
Chlorine	0.29
Sulfur	2.51
Ash	9.70
Oxygen (by difference)	6.88
TOTAL	100.00

Table 4.2.2 Limestone Analysis

	Dry Basis, %
Calcium Carbonate, CaCO3	80.40
Magnesium Carbonate, MgCO3	3.50
Silica, SiO2	10.32
Aluminum Oxide, Al2O3	3.16
Iron Oxide, Fe2O3	1.24
Sodium Oxide, Na2O	0.23
Potassium Oxide, K2O	0.72
Balance	0.43

4.3 Nominal Plant Sizes and Steam Cycle Conditions

The USC steam cycle conditions selected for this study are listed in Table 4.3.1.

Table 4.3.1 Study Steam Cycle Conditions

	Case 1 A	Case 1B	Case 2	Case 3
Unit Nominal Capacity, MWe	400	400	800	800
Main Steam Pressure, psig	4500	4500	4366	5091
Main Steam Temperature, F	1100	1100	1112	1292
Reheater 1 Inlet Temperature, F	1100	1100	1148	1328
Reheater 2 Inlet Temperature, F	-	1100	-	-
Condenser Back Pressure, "Hg	2.0	2.0	2.0	2.0

The steam cycle conditions for Case 1 are based on, and Case 1B's conditions are identical to, the 400 MWe, double reheat, USC PC plant studied in [4-1]. Cases 1A and 1B represent the integration of several currently available technologies. Although as of the writing of this report, there are no supercritical CFB boilers in operation, CFB furnace design has been well proven through more than a dozen subcritical pressure units of the 250 - 300 MWe class and is now offered commercially at the 400 MWe scale. The once-through technology and steam turbine required by Case 1A has been utilized in numerous PC based-power plants. Case 1A addresses the first of a kind integration of these technologies and is a plant that will be available in the near future. Case 1B can be considered an extrapolation of Case 1A in that it incorporates a steam turbine with double reheat to gain a slight increase in plant efficiency.

Case 2 extrapolates Case 1A to a much larger size and incorporates a modest increase in superheat and reheat steam temperatures (1112ºF and 1148ºF versus 1100ºF and 1100ºF). The CFB boiler for this case will be more than double the size of the largest unit in operation today and will involve significant scale-up. Case 2 represents a CFB power plant that will likely be available in about five years.

Case 3 investigates the effect of advanced USC steam conditions, e.g., 5091 psig/1292ºF/1320ºF. This case represents a long-term target for future power plants as many of its components are not yet commercial, including both the turbine and the boiler. It's high steam temperature and pressure require the use of developmental and very expensive materials. In addition, the CFB boiler needs to incorporate innovative design features because of the diminishing heat head difference between the combustion temperature and the final steam temperature. Assuming the new materials become proven in both reliability and cost, a Case 3 type power plant may be commercial in about 15-20 years.

5.0 400 MWe USC CFB Boiler with Single Reheat (Case 1A)

5.1 Plant Performance and Emissions

Figure 5.1.1 presents a full load heat and material balance for the Case 1A plant; operating conditions/state points are shown in this balance for each of the major plant components and the plant utilizes a 4500 psig/1100°F/1100°F single reheat steam cycle, a modification of the double reheat steam cycle shown in [4-1] for a 400 MWe USC PC plant. The CFB plant turbine generator is a single machine comprised of tandem HP, IP, and LP sections that drive a 3600 RPM hydrogen-cooled generator. Steam enters the high-pressure turbine at a rate of 2,710,000 lb/h at 4515 psia and 1100°F and the 2,198,000 lb/h, 854 psia, 640°F cold reheat steam flow is reheated to 1100°F and 789 psia before entering the IP turbine. The turbine exhausts to a single-pressure condenser operating at 2.0 inches of mercury absolute (Hga) backpressure at full load. The feedwater train consists of seven closed feedwater heaters (four low-pressure and three high pressure), and one open feedwater heater (deaerator). Extractions for feedwater heating, deaerating, and the boiler feed pump are taken from the HP, IP, and LP turbine cylinders, and from the cold reheat piping.

The [4-1] PC plant operates with a 96 percent sulfur capture efficiency and a NOx release rate of 0.16 lb/MMBtu, values that are achieved through the use of wet flue gas desulfurization, low NOx burners, and the selective catalytic reduction (SCR) of nitrogen. The CFB plant has been designed to match those same emission rates but it uses limestone feed to the CFB boiler for in situ sulfur capture and the CFB's relatively low furnace temperature, coupled with the staged injection of combustion air, eliminates the need for "back end" flue gas clean up of these contaminants. For particulate control the CFB plant utilizes a pulse jet, fabric filter to remove over 99.9% of the dust in the flue gas.

Table 5.1.1 summarizes the performance and auxiliary power consumption of the plant at full load and Table 5.1.2 presents its emissions. The plant net power output is 404.9 MWe and it operates with a higher heating value (HHV) efficiency of 40.6 percent or a heat rate of 8,405 Btu/kWh. The ultra supercritical pressure steam cycle results in a plant efficiency that is approximately 13 percent higher (40.6 versus ~36.0 percent) than that of a comparable subcritical pressure CFB plant. As a result, the ultra supercritical plant operates with approximately 11 percent less coal flow and its Table 5.1.2 emissions are approximately 11 percent less than those of a typical subcritical pressure CFB plant.

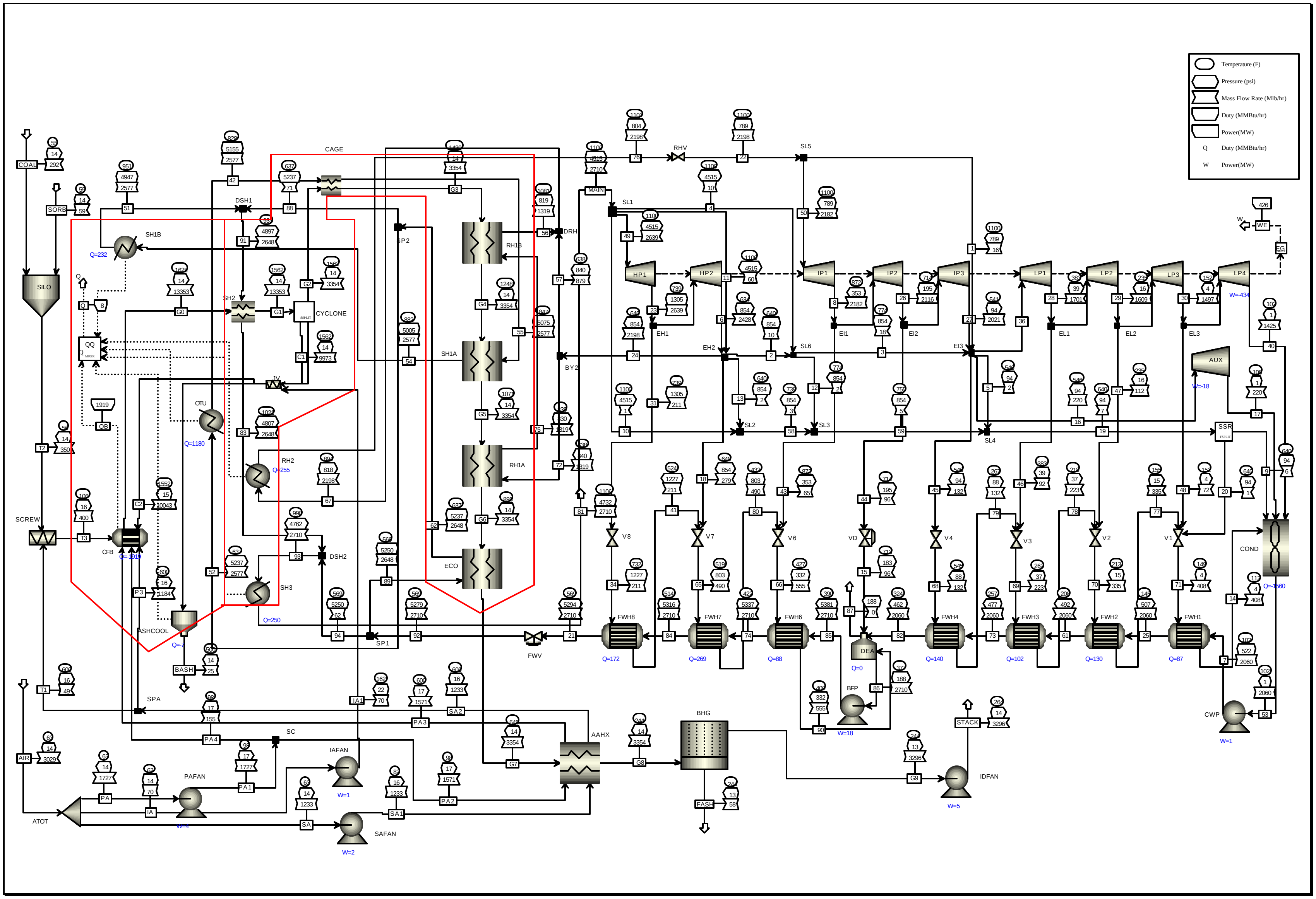


Figure 5.1.1 Case 1A – 400 MWe USC CFB Plant Heat & Material Balance (4500 psig/1100°F/1100°F)

Table 5.1.1 400 MWe Plant Performance and Auxiliary Power Consumption

STEAM CYCLE	
Throttle Pressure, psig	4,500
Throttle Temperature, F	1,100
Reheat 1 Inlet Temperature, F	1,100
Reheat 2 Inlet Temperature, F	N/A
POWER SUMMARY, kWe	
Gross Power at Generator Terminals	426,281
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	150
Coal Feeding	164
Limestone Handling & Feeding	159
Pulverizers	N/A
Condensate Pumps	828
Main Feed Pump (Note 1)	15,772
Booster Feed Pump	N/A
Miscellaneous Balance of Plant (Note 2)	2,050
Primary Air Fans	4,998
Forced Draft Fan	1,481
Induced Draft Fan	3,494
High Pressure Blower	1,436
Baghouse	98
SNCR	N/A
Air Preheater	8
FGD Pumps and Agitators	N/A
Steam Turbine Auxiliaries	652
Circulating Water Pumps	2,547
Cooling Tower Fans	1,751
Transformer Loss	1,022
Ash Handling	562
Total	37,172
Total with Main Feed Pump Deduct	21,400
NET VALUES	
Net Power, kWe	404,881
Net Efficiency [HHV], %	40.6
Net Heat Rate [HHV], Btu/kWhr	8,405
CONDENSER COOLING DUTY, MMBtu/hr	1,560
CONSUMABLES and WASTES	
As Received Coal Feed, lb/hr	291,702
Sorbent Feed, lb/hr	58,551
Ammonia Feed, lb/hr	N/A
Ash, lb/hr	82,970
Scrubber Slurry Discharge, lb/hr	N/A

Note 1 - Driven by auxiliary steam turbine

Note 2 - Inlcudes plant control systems, lighting, HVAC et

Table 5.1.2 Emissions of 400 MWe Single Reheat USC CFB Plant

	lbs/MMBtu	lbs/MWh	Tons/Year*
SO2	0.171	1.441	2,172
NOx	0.160	1.345	2,027
Particulate	0.008	0.070	105
CO2	204	1,717	2,587,910

Note 1: CFB operates with 96% sulfur capture and does not include a polishing scrubber
Note 2: CFB operates without SNCR which would reduce NOx to 0.048 lb/MMBtu
* Assumes 85% capacity factor

5.2 CFB Boiler Conceptual Design

A CFB boiler can be configured in many ways and the designer's goal is to develop an arrangement that both optimizes performance and minimizes cost. As illustrated in Figure 5.2.1, the inter-relationships between the steam cycle conditions, fuel and sorbent characteristics, emission requirements, site conditions and constraints, as well as possible customer preferences will affect the boiler configuration. Many options are available for arranging heat transfer surfaces in the furnace, the INTREX^{TM} fluidized bed heat exchangers, and the HRA of a CFB boiler. The type of surfaces and methods for reheat steam temperature control are illustrated in Figure 5.2.2; they have been described in detail in Section 1.5 and were utilized to develop a conceptual design of the 400 MWe USC CFB boiler.

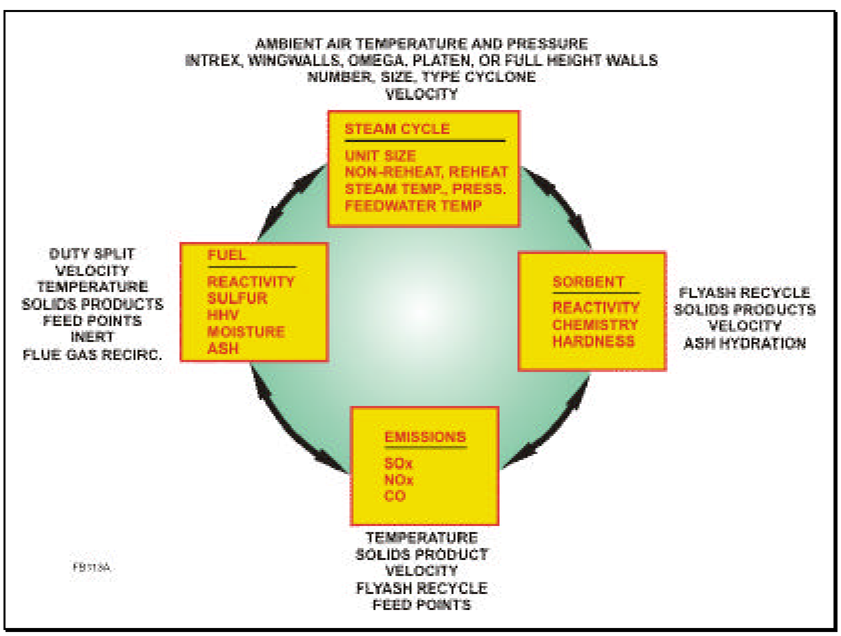


Figure 5.2.1 CFB Boiler Configuration Parameters

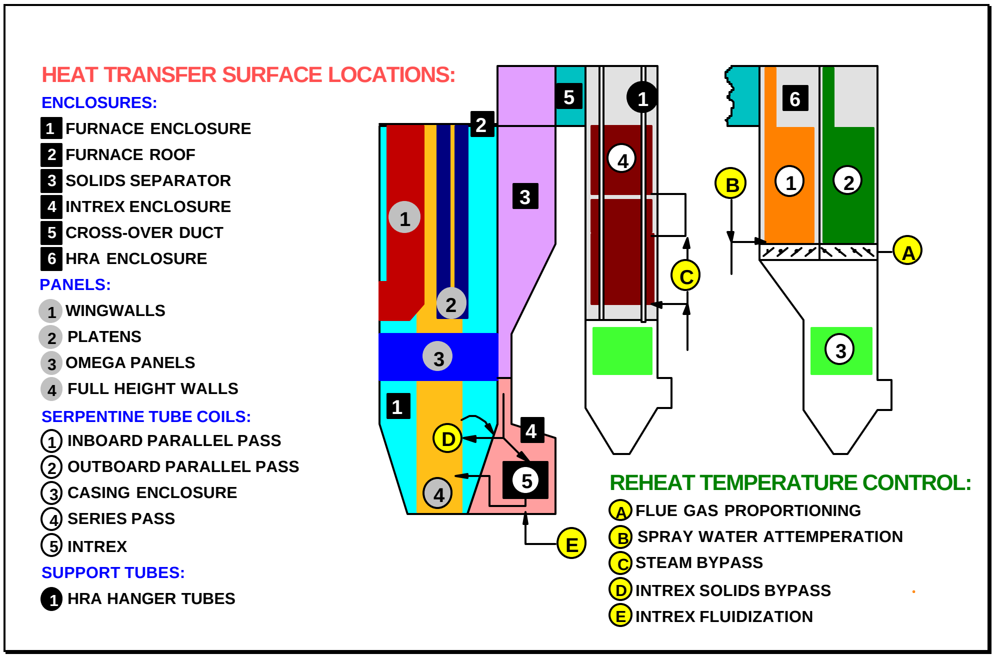


Figure 5.2.2 CFB Heat Transfer Surface Locations and Reheat Temperature Control Options

General Arrangement

The operating conditions of the single reheat, 400 MW_e USC CFB boiler are listed in Table 5.2.1. The CFB boiler operates with a nominal 1600ºF bed/furnace temperature and combusts coal at the rate of 291.7 Mlb/hr with 20 percent excess air to produce 4500 psig 1100°F steam at a rate of 2,710 MM lb/hr. Limestone is injected into the furnace at a rate of 58.6 Mlb/hr for a calcium to sulfur molar feed ratio of 2.4 and 96 percent sulfur capture. The CFB boiler is shown in side, front, and plan views in Figures 5.2.3 and 5.2.4. Including silos, fans, and air heater, the unit occupies an approximate 180 feet by 275 feet footprint and is top supported from structural steel approximately 225 feet above grade. The boiler incorporates Foster Wheeler's standard design features and it is noted it has:

a) 4 silos supplying coal to 14 furnace feed chutes
b) 3 full height furnace evaporative wing walls parallel to the front and back walls
c) 3 full height furnace evaporative wing walls parallel to the side walls
d) 9 pendant superheater panels parallel to front and back walls
e) 8 Compact Solids Separators
f) a series pass HRA
g) 8 INTREX™ Fluidized Bed Heat Exchangers (4 on each side wall)
h) 2 bottom ash stripper coolers (one on each end wall)

Table 5.2.1 400 MWe USC CFB Boiler Operating Conditions

Outlet Steam Conditions:		
Main Steam Flow Rate	Mlb/hr	2,710
Main Steam Temperature	F	1,106
Main Steam Pressure	psia	4,732
Reheat Steam Flow Rate	Mlb/hr	2,198
Reheat Steam Temperature	F	1,101
Reheat Steam Pressure	psia	804
Feedwater Inlet Temperature	F	569
H&M Balance Parameters:		
Flow Rates:		
Flue Gas	Mlb/hr	3,296
Combustion Air	Mlb/hr	3,029
Coal	Mlb/hr	291.7
Limestone	Mlb/hr	58.6
Total Ash	Mlb/hr	83.0
Temperatures:		
Furnace Exit	F	1,600
Flue Gas Entering Air Heater	F	649
Flue Gas Leaving Air Heater	F	244
Bottom Ash	F	500
Excess Air	%	20

The furnace is 33 feet – 5 inches deep, 86 feet – 6 1/2 inches wide, and 157 feet - 6 inches tall. Table 5.2.2 compares these dimensions to those of other units built by Foster Wheeler. The 400 MWe USC CFB boiler is similar in configuration to that of the supercritical pressure 460 MWe Lagiza CFB, but slightly smaller in size because of differences in plant efficiency, unit capacity, fuel and sorbent properties, steam duty distribution, and flue gas volumetric flow rates. Consistent with other Foster Wheeler units, the furnace has one fluidizing air distributor grid and the windbox is tapered to evenly distribute the primary air across the furnace cross section, The single, continuous fluidizing grid simplifies control and with the lower furnace section tapered to increase fluidizing velocities and enhance mixing, coal is injected through seven chutes provided in each side wall at spacings proven to eliminate furnace hot spots. Secondary air is also introduced along the furnace side walls at three elevations to provide staged combustion for minimizing NOx emissions.

Using Foster Wheeler's proprietary 3 dimensional computer codes, the heat fluxes to the furnace walls and the oxygen profile along the centerline of the unit have been determined. Showing a relatively low, uniform profile, the heat flux is typical of a CFB boiler; as a result, the furnace enclosure walls will be fabricated from smooth tubing, whereas, the wing walls, receiving heat from both sides, will be fabricated from rifled tubing. The centerline oxygen profile indicates there is sufficient oxygen along the entire 129 foot- 8 inch furnace width to support combustion and sulfur capture reactions and confirm the adequacy of the proposed furnace configuration.

Table 5.2.2 Comparison of CFB Furnace Dimensions

		400MWe	£agisza	Turow 4-6	JEA	Turow 1-3
Furnace						
- Width	ft.	86.6	90.6	72.2	85.3	69.6
- Depth	ft.	33.5	34.8	33.1	22.0	32.5
- Height	ft.	157.5	157.5	137.8	115.2	142.7

The boiler's eight INTREX^{TM} heat exchangers are of the internal circulating type, see Figure 1.5.8, and one is located below each of the boiler's eight Compact Separators. Table 5.2.3 compares the INTREX^{TM} heat exchangers to those of other units and, having cooling capacities similar to those of JEA, there are no perceived INTREX^{TM} scale-up issues.

Table 5.2.3 Comparison of CFB INTREX^{TM} Heat Exchangers

	400 MWe	£agisza	Turow 4-6	JEA
Number	8	8	8	6
Heat Duty, MW_t	4x33, 4x34	4x18, 4x17	4x12, 4x10	4x19, 2x32

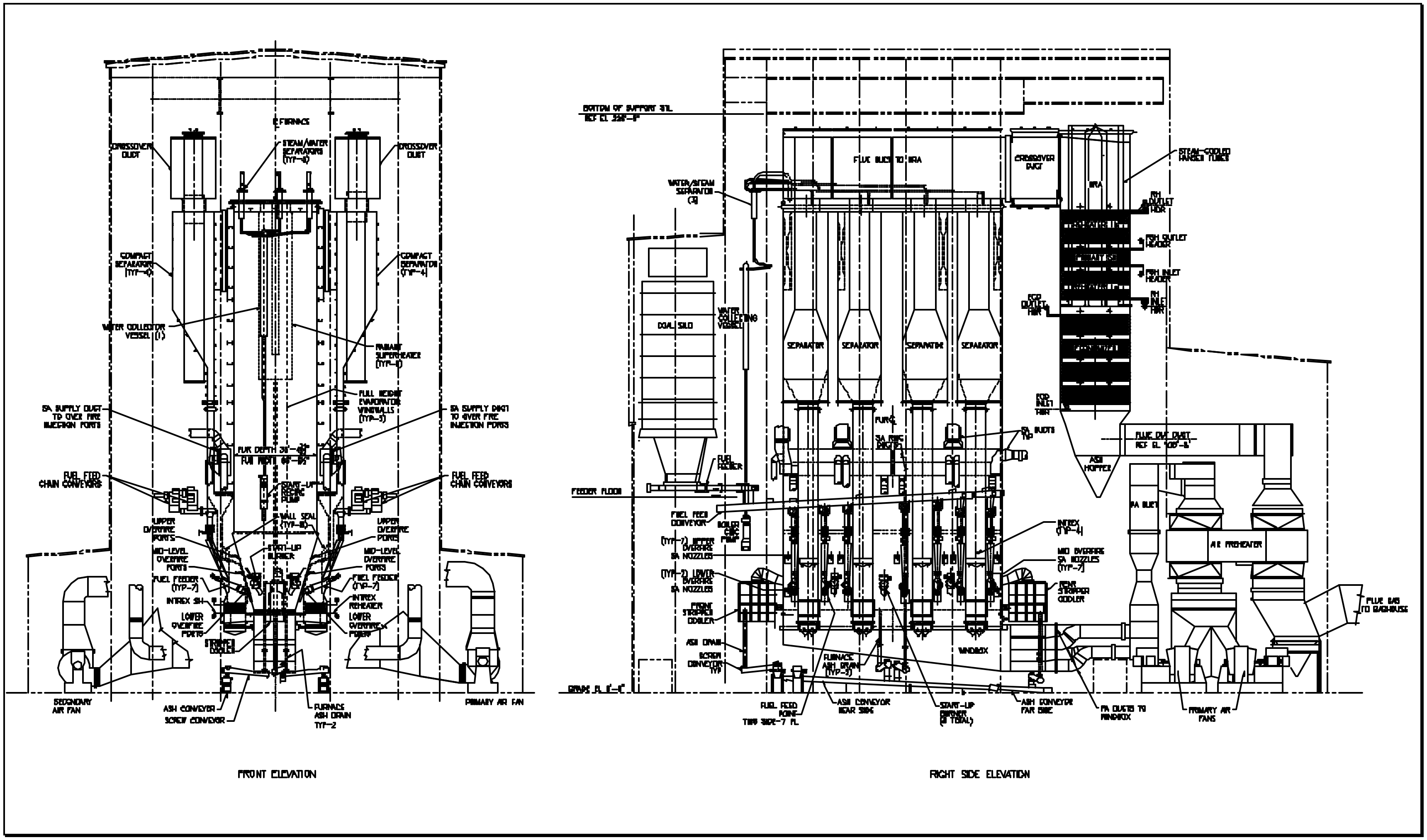


Figure 5.2.3 400 MWe USC CFB Boiler – Front and Side Views

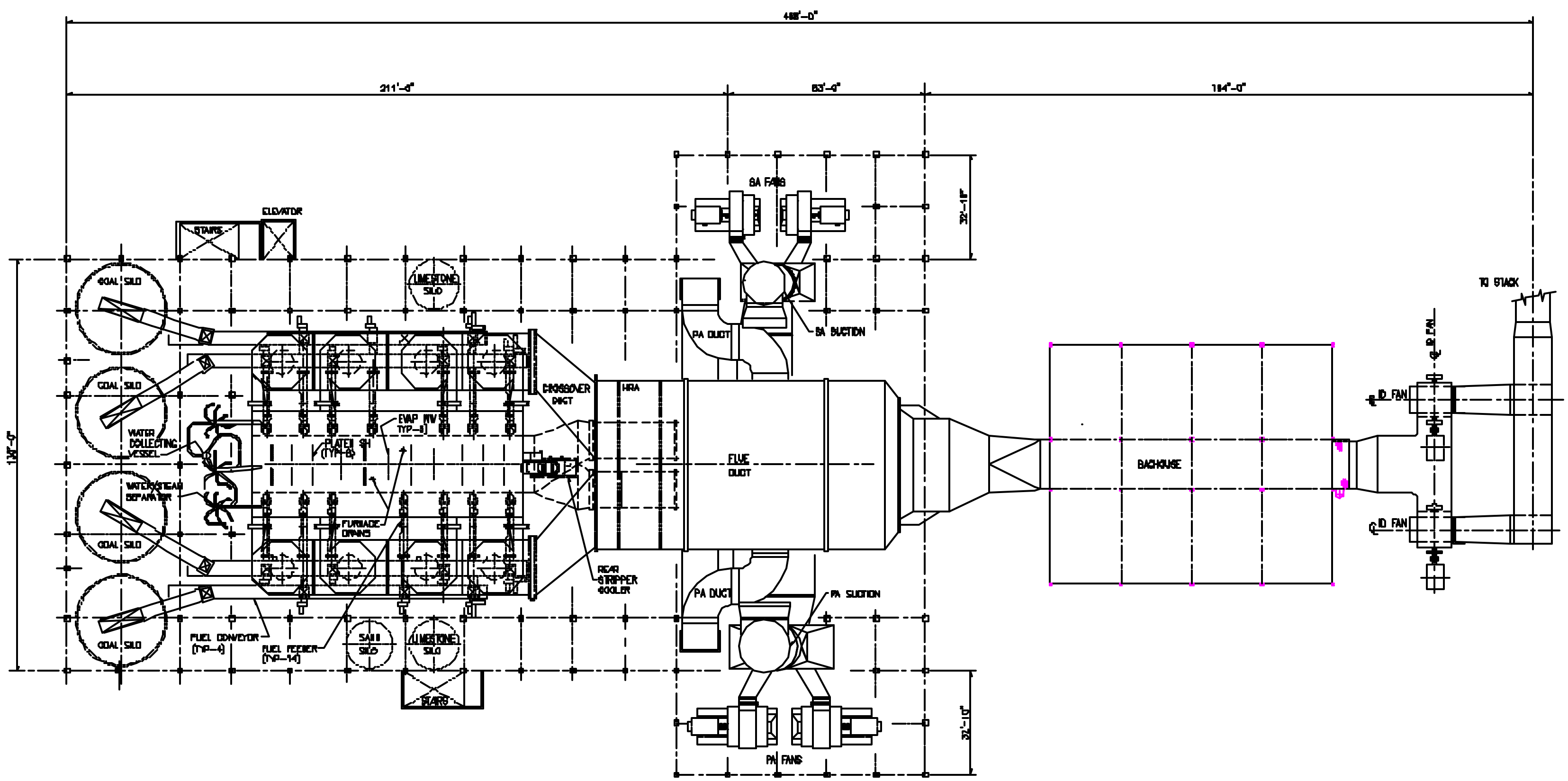


Figure 5.2.4 400 MWe USC CFB Boiler Island – Plan View

Fuel Feed

Coal, crushed to a nominal ½ inch top size, is delivered to four silos positioned along the front wall of the boiler. The four silos have a combined holding capacity of four days of coal with the unit operating at full load. Chain feeders under each silo meter the coal feed rate and drop the fuel onto four chain conveyors (two along each furnace sidewall), which in turn deliver the coal to a total of 14 drop chutes/screw feeders.

Sorbent Feed

Limestone crushed to a nominal top size of 600 microns is stored in two silos positioned adjacent to each furnace sidewall and they have a combined holding capacity of four days of limestone with the unit operating at full load. Six (6) rotary feeders meter the limestone flow rate into the pneumatic transport system that delivers the sorbent to 12 feed points. The limestone is concentrically injected into the furnace through selected lower level secondary air ports.

Draft System

Pairs of radial fans with inlet guide vane control are used for the primary and secondary air supply systems. Balanced draft operation is provide by two (2) axial flow induced draft fans positioned downstream of a baghouse filter. Start-up burner air, INTREX™ fluidization air, and wall seal aeration air is provided by four (4) centrifugal blowers. A tri-sector regenerative air heater positioned under the HRA is used to preheat primary and secondary air for combustion.

Bottom Ash System

A total of two (2) stripper/coolers are provided (one adjacent to the furnace front and rear walls) to cool and recover heat from ash drained from the furnace and to maintain the required solids inventory within the furnace. Cooling and heat recovery is achieved by transferring ash sensible heat into the cold primary air used for fluidization, and by tube bundles through which low temperature condensate is passed. Ash removal rate is controlled by rotary valves that drop the ash onto two drag chain conveyors that run the length of the furnace. Figure 5.2.5 depicts a stripper / cooler attached to the lower furnace wall. For additional ash removal capacity and, for occasional removal of ash from the center of the furnace, two screw coolers are also provided with drain inlets positioned near the center of the furnace.

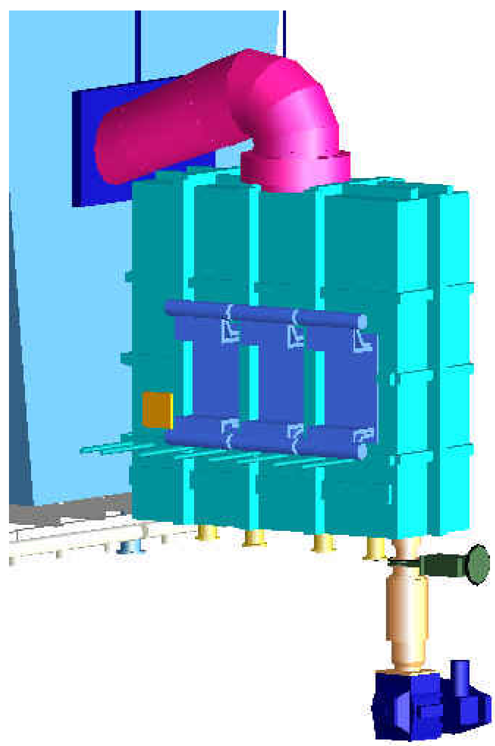


Figure 5.2.5 Bottom Ash Stripper/Cooler

Furnace Hot Loop

The furnace enclosure walls are formed from vertical smooth tubes whereas Foster Wheeler's standard rifling is used in the six, two side heated, full height evaporative wing walls. A total of eight platen superheaters are uniformly spaced at the top of the furnace and the CFB boiler flue gas discharges to eight Compact Solids Separators. An INTREX™ heat exchanger is provided under each separator yielding the arrangement shown in Figure 5.2.6.

Heat Recovery Area (HRA)

Flue gas leaving the solids separators is directed to the HRA via two (2) steam-cooled ducts formed by the continuation of the Compact Separator tubing. Each of these separator outlet ducts directs the flue gas into two (2) steam-cooled crossover ducts which then convey the flue gas to the series pass HRA. The modularly constructed HRA includes a convection reheater (RH-1) and the primary superheater (SH-1), which are supported by steam-cooled hanger tubes. A smooth tube economizer is housed within an un-cooled casing enclosure and is positioned at the bottom of the HRA. Standard features for convection tube bundles (soot blowers, tube spacing, erosion baffles, etc.) consistent with the specified bituminous fuel are incorporated in the HRA.

Figure 5.2.6 Furnace Hot Loop Arrangement

Start-Up Burners

To preheat the furnace bed material to the coal ignition temperature, ten (10) above-bed, oil-fired start-up burners are provided. There are two (2) burners on the furnace front and rear walls, and three (3) on each sidewall.

Steam-Water Circuitry

The CFB boiler steam-water circuitry configuration is shown schematically in Figure 5.2.7. Feedwater from the preheater system enters the boiler via the bare tube economizer located in the lower, uncooled casing section of the series pass HRA. Upon exiting the economizer's multiple tubes the water is collected and transported by a single pipe to the enclosure walls of the INTREX™ fluidized bed heat exchangers. The use of a single transport pipe ensures the water arrives well mixed and at a uniform temperature for distribution among the multiple enclosure walls. The latter are swept in a single parallel flow pass and the exiting water is collected and again transported by a single pipe to the inlet headers of the evaporator (furnace) walls to ensure uniform fluid conditions that minimize the potential for flow unbalances. Surfacing of the economizer and INTREX™ enclosure walls is selected to ensure that subcooled, single-phase water enters the evaporator circuits over the load range as illustrated in Figure 5.2.8. The subcooled water is then heated in the furnace enclosure walls, as well as in full height wing walls/internal panels located at approximately the quarter points of the furnace centerline. The walls and panels are swept in a single parallel flow pass and they convert their water flow to superheated steam before exiting at the top of the furnace. The superheat condition must be maintained over the entire once-through operating range and an evaporator bypass line, that diverts water around the evaporator surfaces to the attemperator station upstream of the radiant platen superheater (SH-2), assures this can be achieved even when burning a variety of fuels that can shift the duty distribution between the furnace hot loop and HRA. The steam from the furnace enclosure walls and evaporator panels is collected and piped to three (3) in-line steam/water separators which are part of the start-up system.

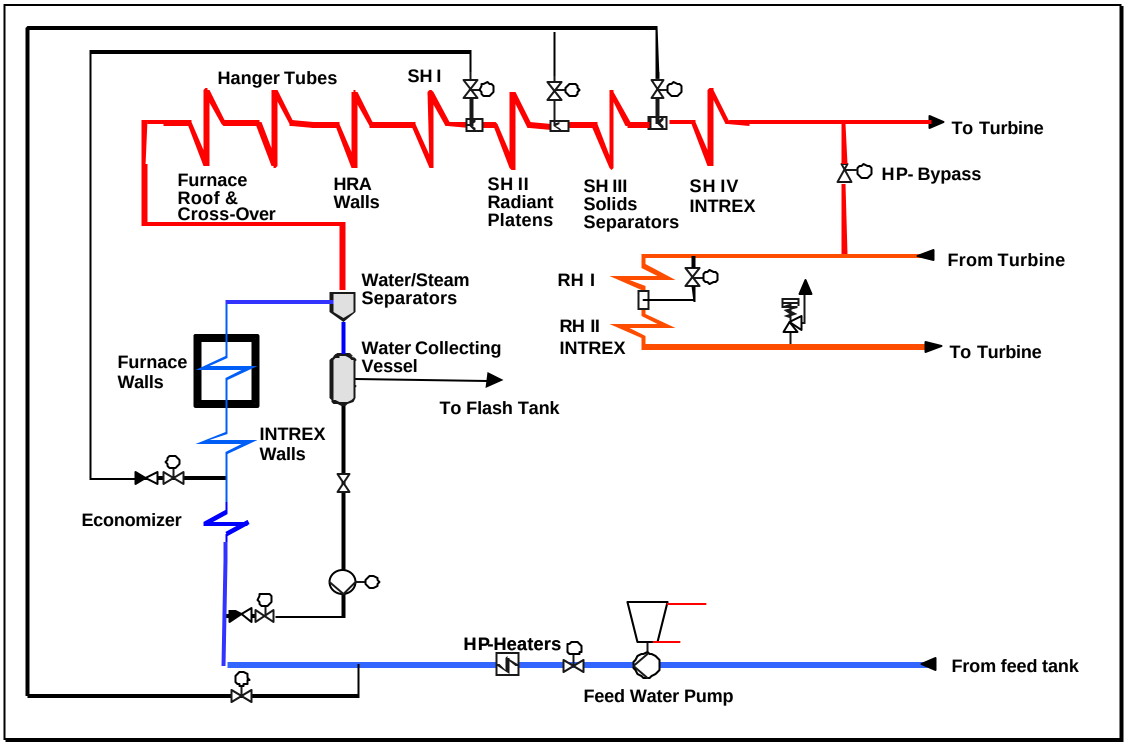


Figure 5.2.7 Steam-Water Circuitry Diagram of 400 MWe USC CFB Boiler

Upon exiting the tangential steam/water separators, the steam is piped to the furnace roof and then through the crossover ducts that connect the two (2) solids separator flue gas outlet ducts to the HRA. The steam is then passed down through the HRA serpentine tube coil support (hanger) tubes which feed steam into the lower HRA enclosure inlet headers. From the HRA enclosure, the steam is passed through the convection superheater (SH-1) which is positioned in between the upper and lower tube bundles of the convection reheater (RH-1). Steam is then directed to eight (8) radiant platen superheater panels (SH-2) located in the upper furnace where the solids density is lowest. The bottom of the panels is covered with refractory as is standard practice to protect against any possible erosion. From SH-2, steam is directed down in parallel through the eight (8) Compact Solids Separators (SH-3). The separator walls are formed with gas tight membrane walls and are covered with a thin, high conductivity refractory lining. Final superheat is then achieved with the steam passing in parallel flow through four (4) of the INTREX^{TM} superheaters positioned on one of the furnace sidewalls. Spray water attemperators are located in the piping upstream of the Compact Separators (SH-3) and upstream of the INTREX^{TM} superheaters (SH-4).

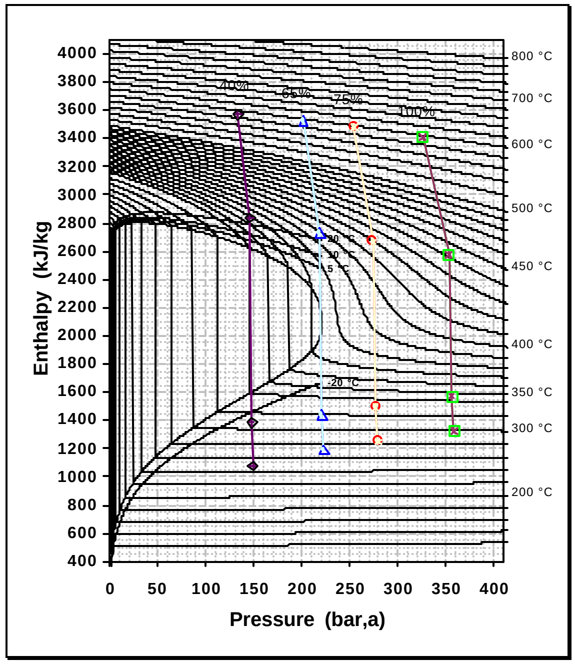


Figure 5.2.8 Pressure-Enthalpy Diagram

Initial steam reheat is accomplished in the series pass HRA in the upper and lower tube bundles of RH-1. During high load operation a portion of the reheat steam flow is bypassed around RH-1 to control final reheat steam temperature. The full reheat steam flow is then passed in parallel through four (4) of the INTREX^{TM} heat exchangers positioned on the left furnace sidewall. The primary means for reheat steam temperature control is by modulation of the reheat steam bypass flow. The amount of modulation necessary can be adjusted by variation of INTREX^{TM} fluidizing velocities and the amount of solids bypass, both of which can be used to regulate the amount of heat absorbed in the reheat circuitry.

Start-Up System

Before fuel can be fired in a once-through boiler, a minimum fluid mass flow rate must be established within the evaporator tubes that form the furnace enclosure and full height wing walls to protect them from overheating. This minimum flow can be provided by the feedwater pump or preferably (as shown in Figure 5.2.7), by a recirculation pump that returns the heated water back to the boiler in a closed loop for maximum heat recovery. During this start-up phase the boiler is controlled similar to a drum unit by having in-line steam/water separators (Figure 1.3.11) downstream of the evaporator to separate liquid and vapor phases. The load at which boiler control is switched from drum type control to a once-through mode is called the BENSON load (40 percent load for this project). Separated water is drained to a water collecting vessel from which the water is pumped back to the economizer. To ensure that subcooled water enters the pump, a small amount of cold feedwater is piped to the pump inlet line. The proposed design includes three (3) tangential type separators and a single water collecting vessel. The separator design is an optimized configuration developed to minimize pressure loss and also, vessel size. During initial firing, the inventory of water within the evaporator expands. Excess water is drained from the water collecting vessel to a flash tank to maintain an acceptable water level within the water collecting vessel.

Boiler Materials

For the Case 1 steam conditions, the material requirements for most sections of the boiler are conventional, and normal boiler materials can be used (Table 5.2.4). The furnace and solids separator panels, for example, can be manufactured of materials that do not require post-weld heat treatment. Austenitic steel Super 304H is required for the final superheater, and TP347HFG for other high-temperature superheaters and reheaters.

Table 5.2.4 Pressure Part Materials for 400 MWe USC Boiler

Heat Surface	Tube Material	Header Material
Economizer	SA-210 C	SA-106C
Furnace Walls	SA-213 T12	SA-106C
Superheater/Reheaters	SA-213 T12	SA-335 P12
	SA-213 T23	SA-335 P91
	SA-213 TP304H	SA-335 P911
	SA-213 TP347HFG	
	Super 304H	
Steam Piping		
Main Steam Pipe		SA-335 P911

5.3 Balance of Plant Systems

To assure a consistent comparison of USC boiler technologies, e.g., CFB versus PC, the CFB plant has been designed to use, wherever possible and practical, the same balance of plant systems as used by the [4-1] PC plant as follows:

Steam Turbine Generator

The turbine consists of a HP section, IP section, and two double-flow LP sections, all connected to a 3600 rpm generator by a common shaft. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 4500 psig/1100°F. The steam initially enters the HP section, flows through the turbine and returns to the boiler for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 789 psig/1100°F. After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the LP section. The steam divides into two paths and flows through the LP sections exhausting downward into the condenser. The turbine stop valves, control valves, reheat stop valves, and intercept valves are controlled by an electro-hydraulic control system.

The turbine is designed to operate at constant inlet steam pressure over the entire load range and is capable of being converted in the future to sliding pressure operation for economic unit cycling.

Condensate and Feedwater Systems

This system delivers the condensate from the condenser hot well to the deaerator, through the gland steam condenser and the LP feedwater heaters. The system includes one main condenser, two 50 percent capacity motor-driven vertical condensate pumps, one gland steam condenser, four LP heaters, and one deaerator with storage tank.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

The feedwater system delivers the feedwater from the deaerator storage tank to the boiler economizer. One turbine-driven boiler feed pump sized at 100 percent capacity is provided to pump feedwater through the three HP feedwater heaters. The pump is provided with inlet and outlet isolation valves, outlet check valves and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Each feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. Feedwater heater drains cascade down to the next highest extraction pressure heater and finally discharge into the deaerator for HP heaters, or the condenser for the LP heaters . Normal drain level in the heaters is controlled by pneumatic level control valves. High water level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

Circulating Water System

The circulating water system supplies cooling water to condense the main turbine exhaust steam. The system includes two 50 percent capacity vertical circulating water pumps, a multi-cell mechanical draft evaporative cooling tower, and interconnecting piping. The condenser is a single-pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box and the condenser cooling duty is 1560 MMBtu/hr.

Coal, Limestone, and Sand Receiving and Handling

The coal handling system covers the equipment required for unloading, conveying, preparing, and storing the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the inlet of the prepared fuel silos.

The bituminous coal is delivered to the site by unit trains of 100-ton rail cars. Each unit train consists of 100 rail cars that are unloaded by a trestle bottom dumper to two receiving hoppers.

Coal from each hopper is fed directly into a vibratory feeder. The 6" x 0 coal from the feeder is discharged onto belt conveyors that transfer the coal to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron, and then to the reclaim pile. Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3" x 0 in the first of two crushers. The coal then enters the second crusher that reduces the coal size to 1/2 " x 0. The coal is then transferred by conveyor to a transfer tower and onto the boiler area where a tripper loads the prepared coal into one of the four silos along the boiler front wall. The coal silos together with their feeding systems are part of/included in the CFB boiler cost account.

Limestone in a 2 inch by zero size is also delivered to the site by train, unloaded by the above equipment, transferred to a separate pile, reclaimed and transported by conveyors to the two limestone silos located at the CFB boiler. The limestone silos together with their milling and feeding systems are part of/included in the CFB boiler cost account.

The CFB boiler is started with a bed of sand. The sand is delivered to the site by a pneumatic transport truck that blows the sand into a silo located adjacent to the CFB boiler. The sand silo and its feeding system are part of/included in the CFB boiler cost account.

Ash Handling System

The ash handling system includes the equipment required for conveying, preparing, storing, and disposing the fly ash and bottom ash produced on a daily basis by the boiler. The scope of the system is from the baghouse hoppers, air heater hopper collectors, and bottom ash coolers to the truck filling stations.

The fly ash collected in the fabric filter and air heater is conveyed to the fly ash storage silo by a pneumatic transport system using low-pressure air from a blower. The fly ash is discharged through a wet unloader that conditions the fly ash and conveys it through a telescopic unloading chute into a truck for disposal.

The bottom ash from the bed ash coolers is discharged to a drag chain type conveyor for transport to the bottom ash silo. The silos are sized for a nominal holdup capacity of 36 hours of full-load operation. At periodic intervals, a convoy of ash hauling trucks will transit the unloading station underneath the silos and remove a quantity of ash for disposal.

Particulate Removal

A pulse jet type fabric filter is used to remove particulate from the flue gas cleaning it to a release rate of 0.01 lb/MMBtu. The boiler exhaust gas enters the inlet plenum of the fabric filter and is distributed among its multiple modules. Gas enters each module through a vaned inlet near the bottom of the module above the ash hopper. The gas then turns upward and is uniformly distributed through the modules, depositing the fly ash on the exterior surface of the bags. Clean gas passes through the fabric and into the outlet duct through poppet dampers. From the outlet dampers the gas proceeds to two downstream induced draft fans.

Periodically each module is isolated from the gas flow, and the fabric is cleaned by a pulse of compressed air injected into each filter bag through a venturi nozzle. This cleaning dislodges the dust cake collected on the filter bag exterior. The dust falls into the ash hopper and is removed through the ash handling system.

Ducting and Stack

The stack is constructed of reinforced concrete with a liner. The stack is sized for adequate dispersion of criteria pollutants, to assure that ground level concentrations are within regulatory limits.

Waste Treatment System

An onsite water treatment facility treats all runoff, cleaning wastes, blowdown, and backwash to within U.S. Environmental Protection Agency (EPA) standards for suspended solids, oil and grease, pH, and miscellaneous metals. All waste treatment equipment is housed in a separate building. The waste treatment system consists of a water collection basin, three raw waste pumps, an acid neutralization system, an oxidation system, flocculation, clarification/thickening, and sludge de-watering. The water collection basin is a synthetic-membrane-lined earthen basin, which collects rainfall run-off, maintenance cleaning wastes, and backwash flows.

The raw waste is pumped to the treatment system at a controlled rate by the raw waste pumps. The neutralization system neutralizes the acidic wastewater with hydrated lime in a two-stage system, consisting of a lime storage silo/lime slurry makeup system with 50-ton lime silo, a 0 - 1,000 lb/hour dry lime feeder, a 5,000-gallon lime slurry tank, slurry tank mixer, and 25 gpm lime slurry feed pumps.

The oxidation system consists of a 50 scfm air compressor, which injects air through a sparger pipe into the second-stage neutralization tank. The flocculation tank is fiberglass with a variable speed agitator. A polymer dilution and feed system is also provided for flocculation. The clarifier is a plate-type, with the sludge pumped to the dewatering system. The sludge is dewatered in filter presses and disposed off-site. The filtrate from the sludge dewatering is returned to the raw waste sump.

Miscellaneous Systems

Miscellaneous systems include fuel oil, service air, instrument air, and service water systems. A 200,000-gallon storage tank provides a supply of No. 2 fuel oil used for startup and for a small auxiliary boiler. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

Accessory Electric Plant

The accessory electric plant includes all switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, all wire and cable. It also includes the main power transformer, all required foundations, and standby equipment.

Instrumentation and Control

An integrated plant-wide distributed control and monitoring system (DCS) is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of multiple video monitor (CRT) and keyboard units. The CRT/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability. The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented in a supervised manual mode but with the capability for operator selection of modular automation routines available.

Buildings and Structures

A soil-bearing load of 5,000 lb/ft^2 is used for foundation design. Foundations are provided for the support structures, pumps, tanks, and other plant components. The following buildings are included in the design basis:

- Steam turbine building
- Boiler building
- Administration and service building
- Makeup water and pretreatment building
- Pump house and electrical equipment building
- Fuel oil pump house
- Continuous emissions monitoring building
- River water intake structure
- Guard house
- Runoff water pump house
- Industrial waste treatment building

5.4 Plant Costs and Economics

The 404.9 MWe USC CFB boiler system shown in Figure 5.2.3, complete with silos, limestone milling, coal and limestone feeding, CFB boiler, air heater, fans, flues, ducts, ash coolers, ash conveyors, and structural steel, is estimated to cost, delivered to the site and erected with union labor, $248.3 million in January 2006 dollars. In Table 5.4.1 the CFB system costs are shown along with the balance of plant cost elements and the plant has a bare erected cost (equipment plus field labor and materials) of $518.8 million. Adding 10 percent for architect/plant engineering, construction management, home office costs, and fee plus 10 percent for project contingency yields a total plant cost of $627.8 million or $1,551/kW.

As discussed in Section 3, the TPC assumes over night construction and Table 5.4.2 adds $85.9 million for interest during construction to obtain a TPI of $713.7 million. The addition of start up costs, inventory capital, land, etc. yields a TCR of $734.8 million. O&M costs, operating costs, and fuel costs are also shown and together with a levelized carrying charge lead to a 20 year levelized cost of electricity of $52.21/MWhr.

Table 5.4.1 Total Plant Cost Summary – Nominal 400 MWe USC CFB Boiler Plant

Equipment Plus Field Labor & Materials		Thousands of Jan 2006 Dollars	$/kW
USC CFB Boiler System*		248,254	
Balance of Plant			
Fuels handling & storage	11,111		
Sorbent handling systems	6,730		
Ash handling & storage	6,517		
Baghouse	11,585		
FGD	0		
Stack	4,868		
Steam turbine-generator	42,003		
Feedwater heaters	2,931		
Condenser	2,969		
Pumps	4,176		
Cooling tower	3,392		
Water treatment systems	3,130		
Miscellaneous equipment	326		
Piping systems	34,852		
Distributed control system	2,875		
Continuous emission monitors	398		
Local control systems	1,635		
Electrical - transformer/bus ducts	3,170		
Electrical - switchyard	7,652		
Electrical - switchgear, MCCs, etc	15,820		
Electrical - cables/wiring/lighting/communic	37,144		
Buildings	24,090		
Foundations	23,127		
Equipment insulation	6,619		
Fire protection	5,843		
Sitework	7,632		
		270,594	
Total Bare Erected Cost		**518,848**	
Architect Engineering, Constr Mngmnt, Home Office,& Fee		51,885	
Project Contingency		57,073	
Total Plant Cost		**627,806**	**1551**

*Includes silos, limestone milling, coal and limestone feed systems, CFB boiler, air heater, ash cooler, ash conveyors, fans, flues, ducts, and structural steel

Table 5.4.2 Capital Investment & Revenue Requirement Summary Nominal 400 MWe USC CFB Boiler Plant

TITLE/DEFINITION			
Case:	1	Steam Turb:	4500psig/1100F/1100F
Plant Size:	404.9 MWe (net)	Heat Rate:	8,405 BTU/kWhr
Fuel (type):	Illinois No 6 Coal	Fuel Cost:	$1.34/MMBtu
Design/Construction:	40 Months	Book Life:	20 Years
TPC (Plant Cost) Year:	Jan-06		
Capacity Factor:	85.0%		

CAPITAL INVESTMENT:		**$x1000**	**$/kW**
Bare Erected Cost (Process Capital & Facilities)		518,848	
Engineering (incl. Constr Mngmnt, H.O., & Fee)		51,885	
Project Contingency		57,073	
	TOTAL PLANT COST	**627,806**	**1,551**
	AFUDC	85,931	212
	TOTAL PLANT INVESTMENT	**713,737**	**1,763**
Royalty Allowance		0	
Start Up Costs		16,323	
Working Capital		4,756	
Debt Service Reserve		0	
	TOTAL CAPITAL REQUIREMENT	**734,816**	**1,815**
OPERATING & MAINTENANCE COSTS (2006)			
Operating Labor		5,260	
Maintenance Labor		4,580	
Maintenance Material		10,195	
Administrative & Support Labor		1,410	
	TOTAL OPERATION & MAINTENANCE (2006)	21,445	
	FIXED O&M (2006)	**19,301**	
	VARIABLE O&M (2006)	**2,145**	
CONSUMABLE OPERATING COSTS, LESS FUEL (2006)			
Water and Treatment		2,671	
Limestone		3,287	
Ash Disposal		3,099	
Other Consumables		1,050	
	TOTAL CONSUMABLES (2006)	**10,107**	
BY-PRODUCT CREDITS (2006)		0	
FUEL COST (2006)			
Coal	**FUEL COST (2006)**	**34,012**	
		1st Year (2009)	**20 Year Levelized**
PRODUCTION COST SUMMARY		**$/MWhr**	**$/MWhr**
	Fixed O&M	6.40	6.40
	Variable O&M	0.71	0.71
	Consumables	3.35	3.35
	By-Product Credit	0.00	0.00
	Fuel	11.28	11.28
	TOTAL PRODUCTION COST (2006)	**21.75**	**21.75**
	LEVELIZED 20 YEAR CARRYING CHARGES (Capital)*		**30.46**
	LEVELIZED 20 YEAR BUSBAR COST OF POWER		**52.21**

***Levelized Fixed Charge Rate = 12.5%**

Reference [4-1] estimated that a PC plant operating with conventional, supercritical pressure conditions (3500psig/1050ºF/1050ºF) and producing 401.8 MWe of net power would cost $1,173/kW in January 1998 dollars. A 550 MWe update of that plant is in preparation for the DOE and, it is believed it will show a new total plant cost of approximately $1,350/kW (January 2006 dollars) with a 10 year levelized cost of electricity of approximately $50/MWhr. Recognizing that the updated plant's larger size gives it an economy of scale advantage and that many assumptions are involved in calculating plant performance, costs, and economics, a comparison of values calculated by different investigators must be done with caution. With Table 5.4.2 indicating the 400 MWe USC CFB plant will have a TPC of $1,551/kW and a levelized cost of electricity of $52.21/MWhr, a comparison of the two plants indicates CFB boilers will remain competitive with PC plants even under USC steam conditions.

6.0 400 MWe USC CFB with Double Reheat (Case 1B)

6.1 Plant Performance

Figure 6.1.1 presents a full load heat and material balance for Case 1B, a nominal 400 MWe CFB plant with 4500 psig/1100°F/1100°F/1100°F double reheat identical to that of the [4-1] PC plant. The high pressure turbine receives 2,440 Mlb/h steam at 4515 psia and 1100°F. The first cold reheat flow is 2,091 Mlb/h of steam at 1356 psia and 753°F, which is reheated to 1100°F and 1249 psia for return to the turbine. The second cold reheat flow is 1,783 Mlb/h of steam at 378 psia and 756°F, which is reheated to 1100°F and 348 psia before entering the low pressure portion of the turbine.

The turbine generator is a single machine comprised of tandem VHP, HP, IP, and LP sections driving a 3600 RPM hydrogen-cooled generator. The turbine exhausts to a single-pressure condenser operating at 2.0 inches Hga backpressure at full load. The feedwater train consists of seven closed feedwater heaters (four low-pressure and three high pressure), and one open feedwater heater (deaerator). Extractions for feedwater heating, deaerating, and the boiler feed pump are taken from the VHP, HP, IP, and LP turbine cylinders, and from the cold reheat piping.

Tables 6.1.1 and 6.1.2 present the performance and emissions of the double reheat CFB plant. The CFB plant has a net power output of 402.3 MWe and it operates with an efficiency of 41.2 percent, the latter corresponding to a heat rate of 8,283 Btu/kWh. Also included in Table 6.1.1 is the performance of the comparable [4-1] double reheat PC plant. The steam conditions, auxiliary power consumption, and electrical output of the two plants are similar and, as a result, they operate with similar efficiencies, the PC plant producing 399.7 MWe at an efficiency of 41.4 percent.

The CFB plant has been designed to the same emissions requirements as the [4-1] PC plant. Although the emissions of the two plants are essentially the same, the plants use different emission control technologies. The PC plant uses post combustion, wet FGD for SO_2 control, low NOx burners followed by SCR for NOx control, and an electrostatic precipitator for particulate control. The CFB plant, in contrast, uses limestone feed to the CFB boiler for in situ sulfur capture (96 percent SO_2 removal) and the CFB's relatively low furnace temperature, coupled with the staged injection of combustion air, enables it to control its NOx emissions to below 0.16 lb/MMBtu. For particulate control the CFB plant utilizes a pulse jet, fabric filter to remove over 99.9% of the dust in the flue gas.

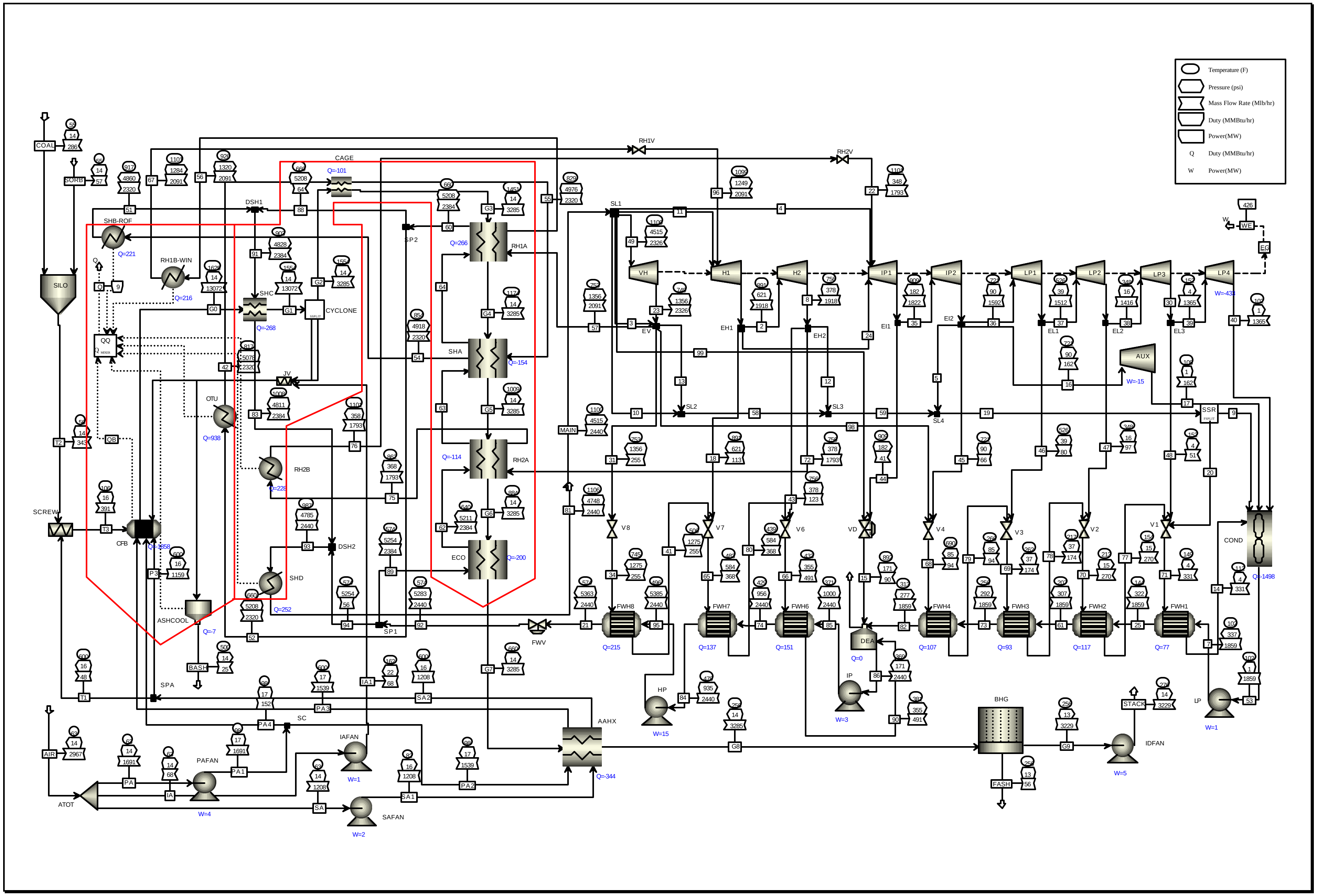


Figure 6.1.1 Case 1B – 400 MWe USC CFB Plant with Double Reheat (4500 psig/1100°F/1100°F/1100°F)

Table 6.1.1 Double Reheat 400 MWe Plant Performance

		400 MW CFB	400 MW PC
STEAM CYCLE			
	Throttle Pressure, psig	4,500	4,500
	Throttle Temperature, F	1,100	1,100
	Reheat 1 Inlet Temperature, F	1,099	1,100
	Reheat 2 Inlet Temperature, F	1101	1,100
POWER SUMMARY, kWe			
	Gross Power at Generator Terminals	425,791	425,000
AUXILIARY LOAD SUMMARY, kWe			
	Coal Handling	147	180
	Coal Feeding	161	N/A
	Limestone Handling & Feeding	154	790
	Pulverizers		1,540
	Condensate Pumps	747	780
	Main Feed Pump (Note 1)	14,550	14,000
	Booster Feed Pump	2,485	2,600
	Miscellaneous Balance of Plant (Note 2)	2,050	2,050
	Primary Air Fans	4,894	900
	Forced Draft Fan	1,451	900
	Induced Draft Fan	3,423	5,489
	High Pressure Blower	1,395	N/A
	Baghouse	96	100
	SNCR		80
	Air Preheater	8	
	FGD Pumps and Agitators		2,800
	Steam Turbine Auxiliaries	652	650
	Circulating Water Pumps	2,446	2,400
	Cooling Tower Fans	1,681	1,650
	Transformer Loss	1,022	1,020
	Ash Handling	548	1,410
	Total	37,910	39,339
	Total with Main Feed Pump Deduct	23,360	25,339
NET VALUES			
	Net Power, kWe	402,431	399,661
	Net Efficiency [HHV], %	41.2	41.4
	Net Heat Rate [HHV], Btu/kWhr	8,283	8,251
CONDENSER COOLING DUTY, MMBtu/hr		1,498	1,475
CONSUMABLES and WASTE			
	As Received Coal Feed, lb/hr	285,722	282,675
	Sorbent Feed, lb/hr	57,285	28,790
	Ammonia Feed, lb/hr	N/A	204
	Ash, lb/hr	81,235	28,131
	Scrubber Slurry Discharge, lb/hr	N/A	284,450
Note 1 - Driven by auxiliary steam turbine			
Note 2 - Inlcudes plant control systems, lighting, HVAC etc			

Table 6.1.2 Double Reheat 400 MWe USC CFB Plant Emissions

	lbs/MMBtu	lbs/MWh	Tons/Year*
SO2	0.171	1.420	2,127
NOx	0.160	1.325	1,986
Particulate	0.008	0.069	103
CO2	204	1,692	2,534,771

Note 1: CFB operates with 96% sulfur capture and does not include a polishing scrubber
Note 2: CFB operates without SNCR which would reduce NOx to 0.048 lb/MMBtu
* Assumes 85% capacity factor

Comparing the double reheat CFB plant performance to that of the single reheat CFB plant of Table 5.1.1, the use of double reheat increased the plant efficiency by 0.6 percentage points (41.2 versus 40.6 percent). Since the gain in efficiency is only 0.6 percentage points, the cost effectiveness of this gain vis a vis the increase in plant capital costs and operating complexity can be questioned. In [6-1] the cost effectiveness of double reheat PC plants has been studied and double reheat was found to be one of the most costly means for improving efficiency. Aside from some early units, few subcritical pressure, double reheat plants have been built in the US and, since there is little reason why USC pressure steam cycles would reverse this, no further analysis was conducted on this case.

7.0 800 MWe USC CFB Boiler (Case 2)

7.1 Plant Performance and Emissions

Figure 7.1.1 presents a full load heat and material balance for the Case 2 plant; operating conditions/state points are shown in this balance for each of the plant's major components and the overall plant. Utilizing a single reheat steam turbine with 4336 psig/1112°F/1148°F steam conditions, the plant is a modification of the double reheat steam cycle shown in [4-1] for a 400 MWe PC plant.

The CFB plant turbine generator is a single machine comprised of tandem HP, IP, and LP sections that drive a 3600 RPM hydrogen-cooled generator. Steam enters the high-pressure turbine at a rate of 4,470 Mlb/h and after reheating is delivered to the IP turbine at a rate of 3,867 Mlb/h at 638 psig and 1148°F. The turbine exhausts to a single-pressure condenser operating at 2.0 inches Hga backpressure at full load. The feedwater train consists of eight closed feedwater heaters (five low-pressure and three high pressure), and a deaerator. Extractions for feedwater heating, deaerating, and the boiler feed pump are taken from the HP, IP, and LP turbine cylinders, and from the cold reheat piping.

The CFB plant has been designed to the same emissions requirements as the [4-1] PC plant. Similar to the 400 MWe CFB, the 800 MWe CFB plant uses limestone feed to the CFB boiler for in situ sulfur capture (96 percent SO_2 removal), staged combustion to control NOx emissions to below 0.16 lb/MMBtu, and a pulse jet fabric filter to remove over 99.9% of the dust in the flue gas.

Tables 7.1.1 and 7.1.2 summarize the performance and emissions of the plant at full load. The plant net power output is 740.5 MWe and it operates with an efficiency of 41.3 percent (HHV), which is a heat rate of 8,263 Btu/kWh. Compared with the 400 MWe CFB plant, the 800 MWe plant efficiency is about 2 percent higher (41.3 versus 40.6). This slight improvement in efficiency, which is attributed to an increase in steam reheat temperature (1148 versus 1100ºF) and equipment “economies of scale”, results in about a 2 percent reduction in emissions.

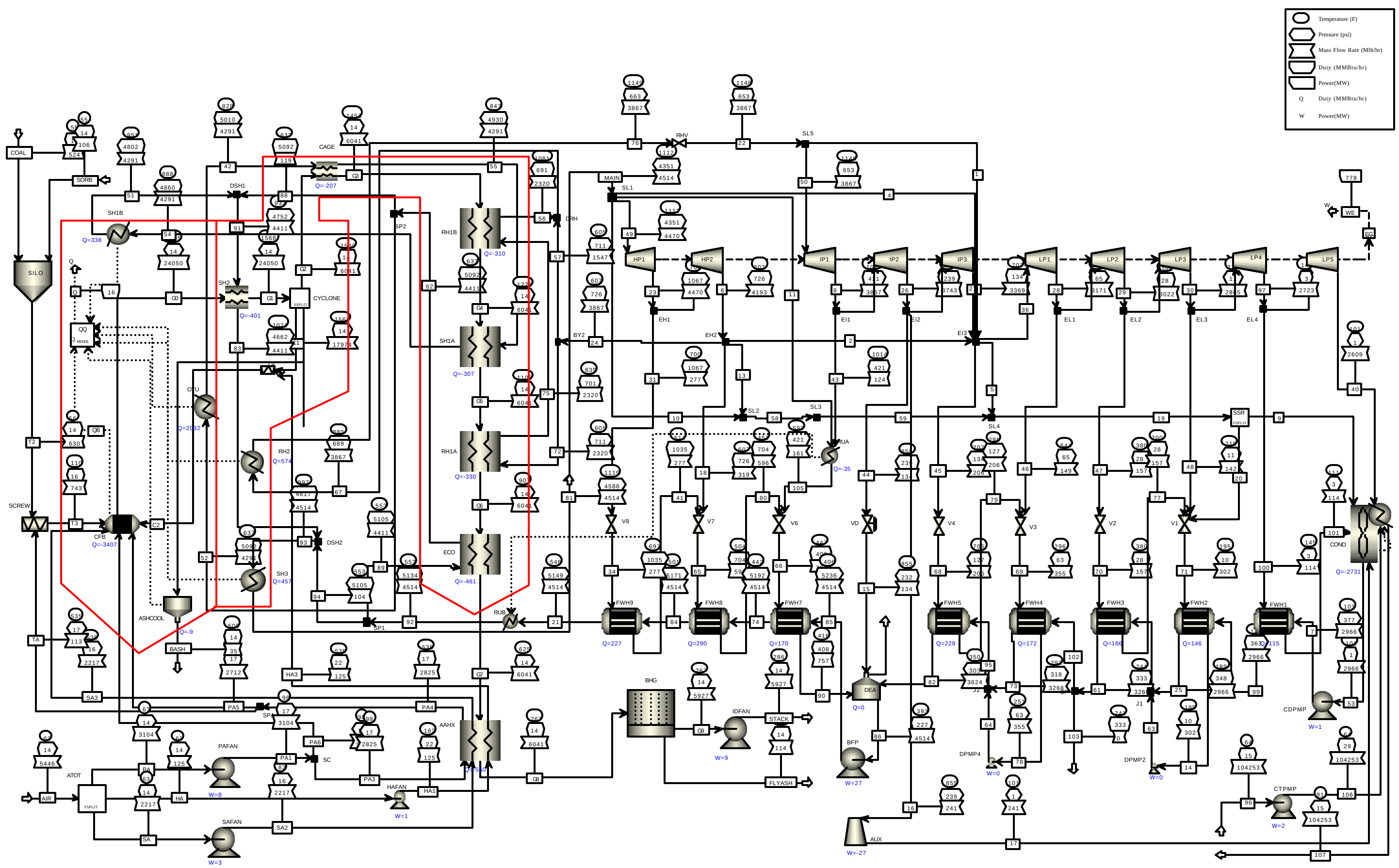


Figure 7.1.1 Case 2 – 800 MWe USC CFB Plant Heat & Material Balance

Table 7.1.1 Nominal 800 MWe USC CFB Plant Performance

STEAM CYCLE	
Throttle Pressure, psig	4,336
Throttle Temperature, F	1,112
Reheat 1 Inlet Temperature, F	1,148
Reheat 2 Inlet Temperature, F	N/A
POWER SUMMARY, kWe	
Gross Power at Generator Terminals	777,642
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	269
Coal Feeding	294
Limestone Handling & Feeding	286
Pulverizers	N/A
Condensate Pumps	1,192
Main Feed Pump (Note 1)	25,482
Booster Feed Pump	N/A
Miscellaneous Balance of Plant (Note 2)	3,000
Primary Air Fans	8,983
Forced Draft Fan	2,663
Induced Draft Fan	6,283
High Pressure Blower	2,564
Baghouse	176
SNCR	N/A
Air Preheater	14
FGD Pumps and Agitators	N/A
Steam Turbine Auxiliaries	1,000
Circulating Water Pumps	4,459
Cooling Tower Fans	3,065
Transformer Loss	1,900
Ash Handling	1,009
Total	62,641
Total with Main Feed Pump Deduct	37,158
NET VALUES	
Net Power, kWe	740,484
Net Efficiency [HHV], %	41.3
Net Heat Rate [HHV], Btu/kWhr	8,263
CONDENSER COOLING DUTY, MMBtu/hr	2,731
CONSUMABLES and WASTE	
As Received Coal Feed, lb/hr	524,486
Sorbent Feed, lb/hr	105,648
Ammonia Feed, lb/hr	N/A
Ash, lb/hr	149,395
Scrubber Slurry Discharge, lb/hr	N/A

Note 1 - Driven by auxiliary steam turbine

Note 2 - Inlcudes plant control systems, lighting, HVAC etc

Table 7.1.2 Nominal 800 MWe USC CFB Plant Emissions

	lbs/MMBtu	lbs/MWh	Tons/Year*
SO2	0.171	1.417	3,905
NOx	0.160	1.322	3,645
Particulate	0.008	0.069	189
CO2	204	1,688	4,653,598

Note 1: CFB operates with 96% sulfur capture and does not include a polishing scrubber
Note 2: CFB operates without SNCR which would reduce NOx to 0.048 lb/MMBtu
* Assumes 85% capacity factor

7.2 Scale-Up Considerations

CFB boilers are commercially available in a nominal 400 MWe size and the move to 800 MWe represents a significant scale-up step. The CFB components/sections to be considered in such a scale-up are:

- Furnace
- Solid Separators
- INTREX™ Fluidized Bed Heat Exchanger
- Convection Pass HRA

Furnace

The design of a CFB furnace involves a careful evaluation of fuel and sorbent characteristics followed by a selection of operating temperature, gas velocity, gas/solids residence times, and solids recirculation rates. Foster Wheeler has developed a comprehensive furnace calculation method that takes the above into consideration and predicts solids density, heat release, pressure drop, and heat transfer profiles throughout the furnace. This model has been verified with a large number of field measurements, including data from the largest CFB boilers in operation e.g. the 235 and 262 MW_e boilers in Turow, Poland and the 300 MW_e JEA boilers.

The amount of particulate contained in the furnace flue gas decreases in going from the bottom to the top of the unit and, given sufficient height, can approach a constant minimum value. With wall heat transfer rates being proportional to the amount of particulate entrained in the gas, furnace heights are typically limited to about 165 feet to maximize the cost effectiveness of its heat transfer surfaces. Similar to the height limitation, there is also a furnace depth limitation. With fuel and secondary air being injected through the side walls of the boiler, the furnace depth is typically limited to approximately 40 feet to insure they are distributed uniformly across the unit. Primary combustion air is admitted at the base of the unit and, to provide highly turbulent mixing of fuel, air, and sorbent plus enhanced solids entrainment, Foster Wheeler narrows the furnace cross section at the base of the unit. With the cross section reduced, there is no need to divide the air distributor into separately controllable sections, instead, a single zone distributor can be used that simplifies control and operation.

With maximum allowable furnace heights and furnace depths established, the main remaining variable in the scale-up process is the width of the furnace. By increasing the width of the furnace, the boiler cross sectional area can be increased to keep flue gas velocities at desired levels. As cross sectional areas are increased, however, the ratio of furnace wall surface area to enclosed volume reduces. Since the furnace walls are used for boiling/evaporation, large CFB boilers must be provided with additional evaporative surfaces, typically wing walls that protrude into the furnace and are connected in parallel with the furnace walls in a single pass water flow arrangement.

The number of fuel feeding and limestone injection points required by large units will be based on the cross section feed areas (pounds per hour per square feet of bed area) proven in smaller units. The same applies also for air distribution and start-up burners. Other auxiliary equipment, such as fans, conveyors, feeders, air heaters, baghouse filters, etc. are similar to those used in large power plants, which means that there will be no scale-up issues in the auxiliary systems.

Solids Separators

Maintaining a high separation efficiency in the CFB boiler's solids separators is key to achieving high combustion efficiency, reduced limestone consumption, and high sulfur capture efficiency. Since the separation efficiency of these devices tends to decrease as physical sizes/diameters are increased, large CFB boilers will use the separator sizes proven most cost effective in smaller size units. Although a large CFB boiler will require a larger number of separators, they will be of a proven size and design (see Figure 1.5.7). By applying them in nominal, 100 MWe furnace-separator module building blocks as shown in Figure 7.2.1, scale-up will not be an issue, especially since Foster Wheeler has already provided several CFB boilers with separators installed on opposing walls.

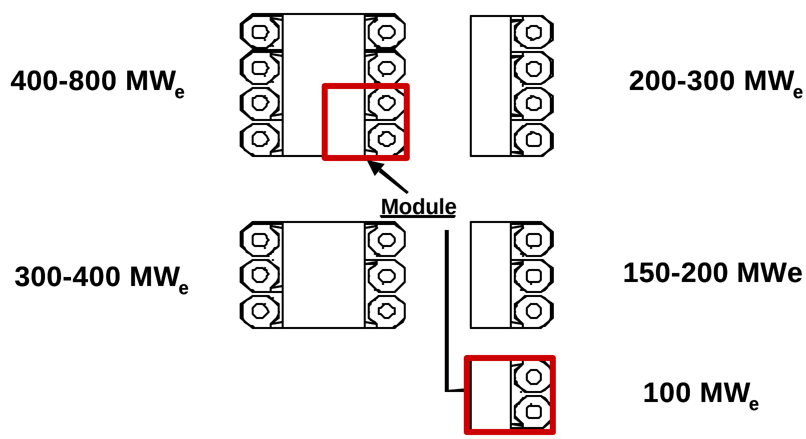


Figure 7.2.1 CFB Furnace-Solids Separator Arrangement: Modularization and Scale-up

Convection Pass HRA

After passing through the furnace solids separators, the nominal 1600ºF flue gas of a large CFB boiler will be cooled by a parallel gas path HRA consisting of convective tube bundles, enclosure walls, a division wall, and gas flow proportioning dampers. With the division wall and enclosure walls steam-cooled and the tube bundles used for superheating, reheating, and feedwater preheating (economizer), the arrangement will be typical of large PC boilers and pose no scale-up issues.

INTREX™ Fluidized Bed Heat Exchanger
If the heat content of the CFB flue gas can not satisfy the plant's superheat and reheat needs, superheat wing walls will be added to the furnace. With evaporative surfaces already added to the furnace, the space for this additional surface may be limited. If this situation develops, then superheat and reheat tube surfaces will be placed in INTREX™ heat exchangers. Since these exchangers provide a dense "package" of highly efficient heat transfer surfaces and have been utilized on several Foster Wheeler CFB boilers, they should not pose a scale-up issue.

7.3 CFB Boiler Conceptual Design

General Arrangement
The operating conditions of the nominal 800 MW_e USC CFB boiler are listed in Table 7.3.1. The CFB boiler operates with a nominal 1600ºF bed/furnace temperature and combusts coal at the rate of 519 Mlb/hr with 20 percent excess air to produce 4573 psig 1119F steam at a rate of 4,514 M lb/hr. Limestone is injected into the furnace at a rate of 106 Mlb/hr for a calcium to sulfur molar feed ratio of 2.4 and 96 percent sulfur capture. The CFB boiler is shown in side, front, and plan views in Figures 7.3.1 through 7.3.3. Including silos, fans, and air heater, the unit occupies an approximate 200 feet by 330 feet foot print and is top supported from structural steel approximately 250 feet above grade. The boiler incorporates Foster Wheeler's standard design features and it is noted it has:

a) 4 coal silos supplying coal to 16 furnace feed chutes
b) 3 full height furnace evaporative wing walls parallel to front and back walls
c) 3 full height furnace evaporative wing walls parallel to the side walls
d) 8 Compact Solids Separators
e) a parallel pass HRA
f) 2 elevations of 8 INTREX™ Fluidized Bed Heat Exchangers
g) 2 bottom ash stripper coolers (one on each end wall)

The furnace is 38 feet deep, 129 feet - 8 inches wide, and 165 feet tall and its dimensions are compared in Table 7.3.2 to those of other units built by Foster Wheeler; this comparison reveals that the move to 800 MWe has been primarily achieved by an increase in furnace width. Although the increase is significant, approximately 50 percent larger than the largest unit built to date, it reflects the addition of furnace-separator modules per the Figure 7.2.1 methodology and, hence, has low risk. Consistent with previous units, the furnace has one fluidizing air distributor plate and, to ensure a uniform distribution of primary air across the enlarged furnace cross section, the primary air plenum is subdivided into four separate compartments each with its own air and control. Coal is injected through eight chutes provided in each side wall at spacings proven to eliminate furnace hot spots. Secondary air is also introduced along the furnace side walls at three elevations to provide staged combustion for minimizing NO_x emissions. Using Foster Wheeler's proprietary 3 dimensional computer codes, the heat fluxes to the furnace walls and the oxygen profile along the centerline of the unit have been determined and are shown in Figures 7.3.4 and 7.3.5, respectively. Showing a relatively low, uniform profile, the heat flux is typical of a CFB boiler; as a result, the furnace enclosure walls will be fabricated from smooth tubing, whereas, the wing walls, receiving heat from both sides, will be fabricated from rifled tubing. The centerline oxygen profile indicates there is sufficient oxygen along the entire 129 foot- 8 inch furnace width to support combustion and sulfur capture reactions. These plots confirm the adequacy of the proposed furnace configuration.

Table 7.3.1 Nominal 800 MWe USC CFB Boiler Operating Conditions

<u>Outlet Steam Conditions:</u>		
Main Steam Flow Rate	Mlb/hr	4,514
Main Steam Temperature	F	1,119
Main Steam Pressure	psia	4,573
Reheat Steam Flow Rate	Mlb/hr	3,867
Reheat Steam Temperature	F	1,148
Reheat Steam Pressure	psia	648
Feedwater Inlet Temperature	F	553
<u>H&M Balance Parameters:</u>		
Flow Rates:		
Flue Gas	Mlb/hr	5,927
Combustion Air	Mlb/hr	5,446
Coal	Mlb/hr	524.5
Limestone	Mlb/hr	105.6
Total Ash	Mlb/hr	149.4
Temperatures:		
Furnace Exit	F	1,568
Flue Gas Entering Air Heater	F	625
Flue Gas Leaving Air Heater	F	267
Bottom Ash	F	500
Excess Air	%	20

Table 7.3.2 CFB Furnace Dimension Comparison

		800 MWe	£agisza	Turow 4-6	JEA	Turow 1-3
Furnace						
- Width	ft.	131.2	90.6	72.2	85.3	69.6
- Depth	ft.	39.4	34.8	33.1	22.0	32.5
- Height	ft.	164.0	157.5	137.8	115.2	142.7

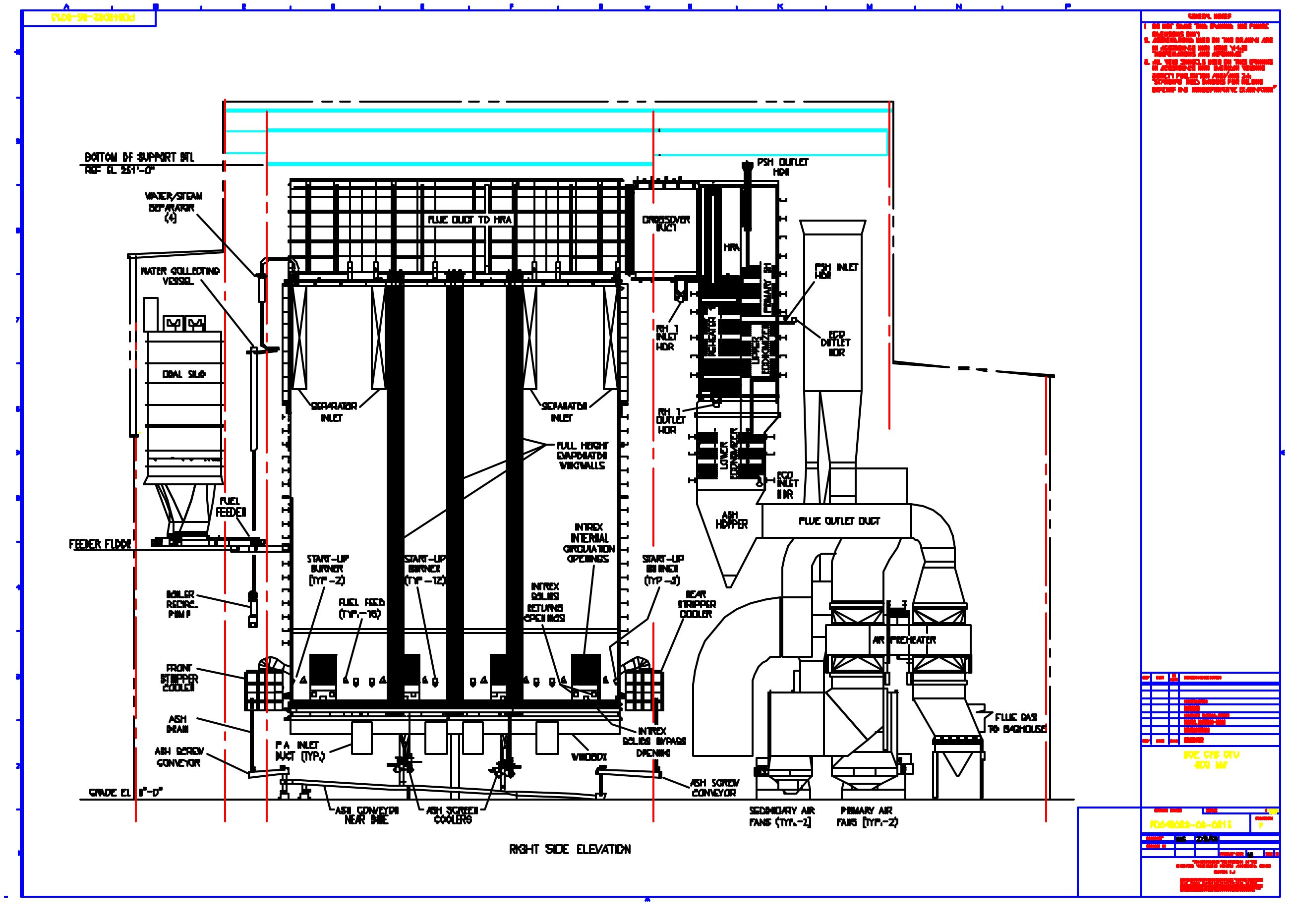


Figure 7.3.1 Nominal 800 MWe USC CFB Boiler Side View

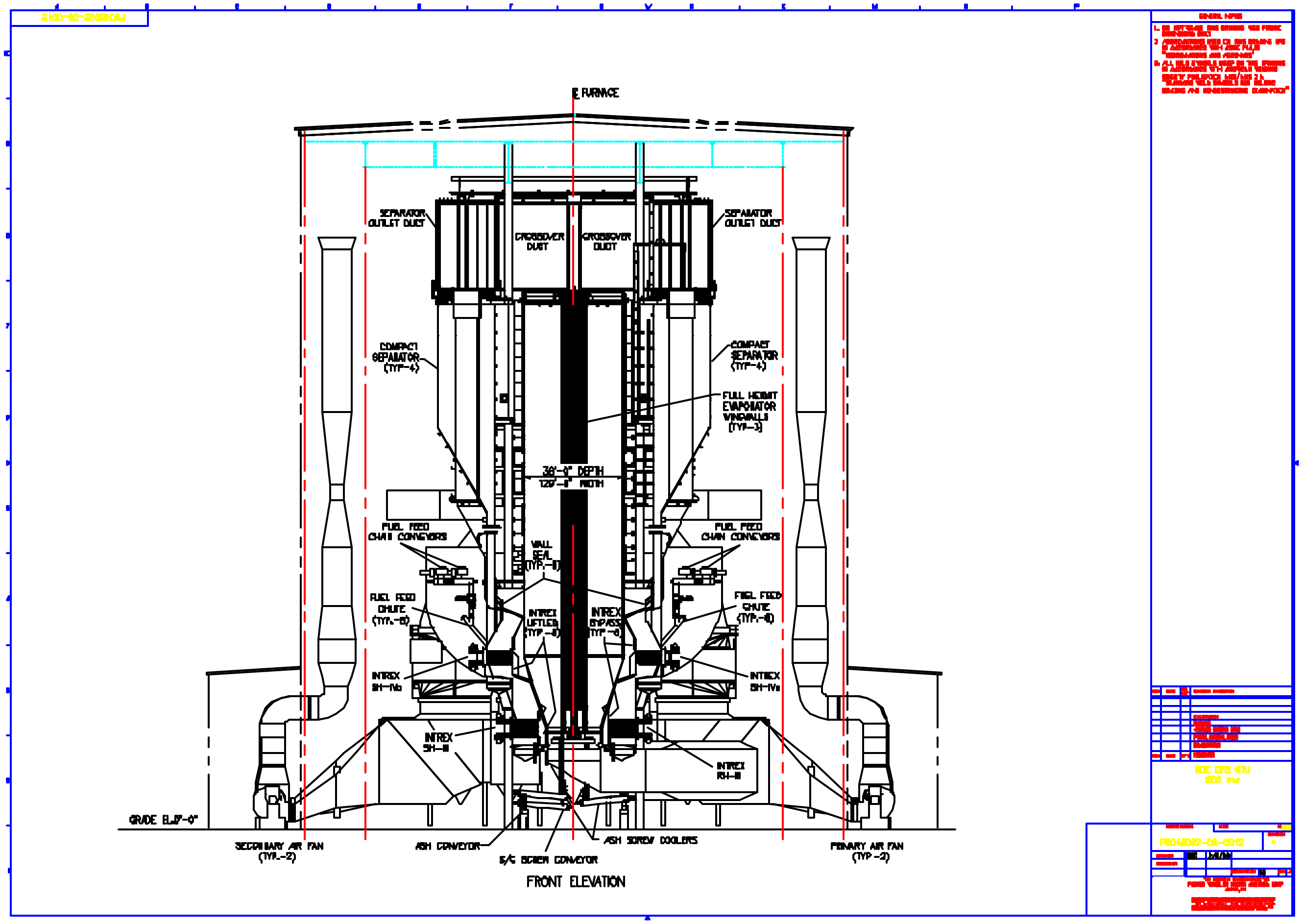


Figure 7.3.2 Nominal 800 MWe USC CFB Boiler Front View

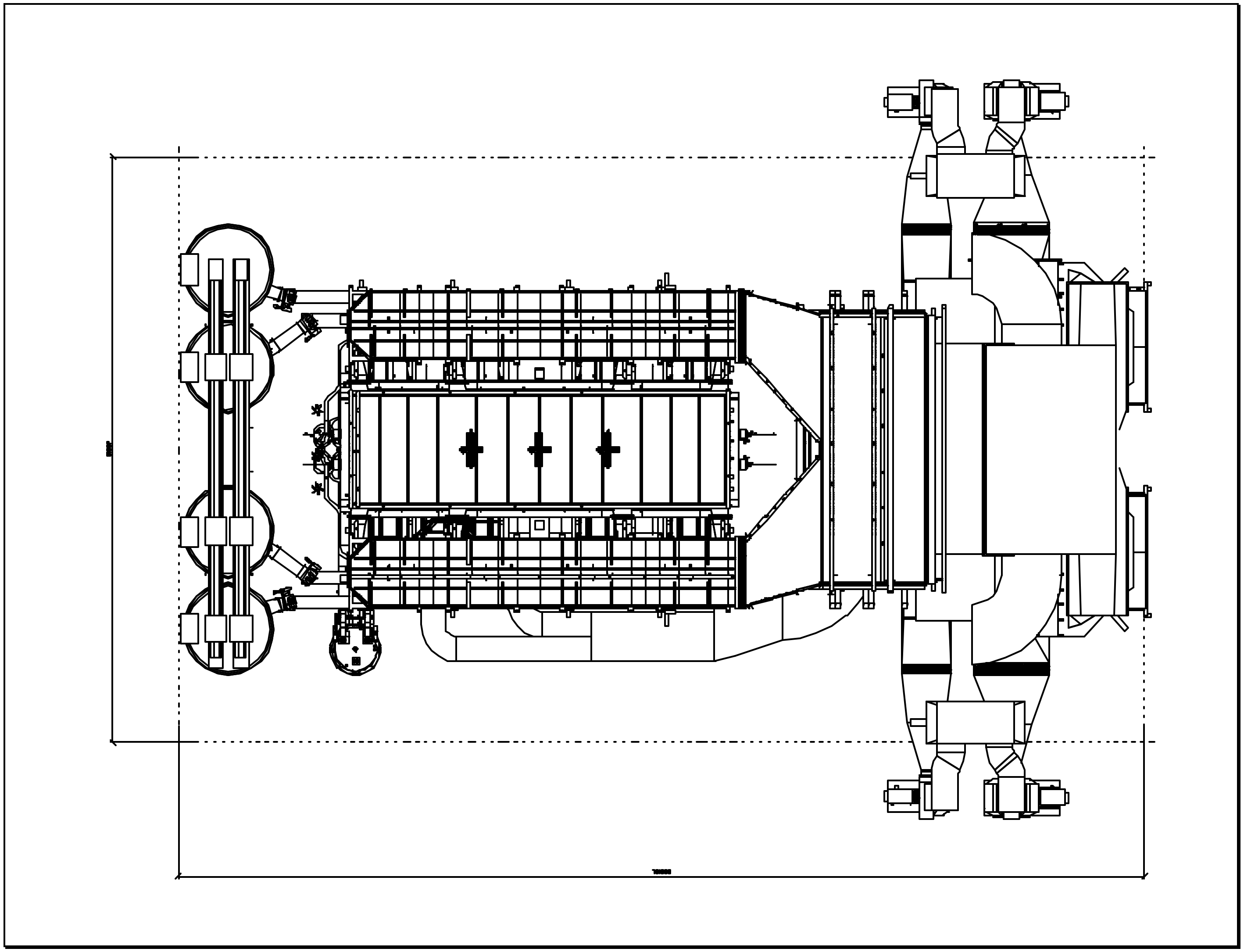


Figure 7.3.3 Nominal 800 MWe USC CFB Boiler Plan View

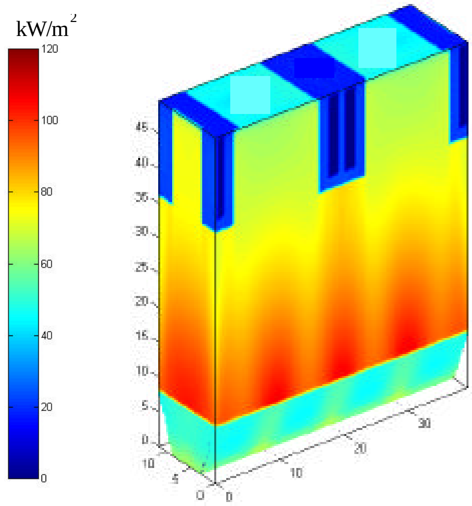


Figure 7.3.4 Furnace Wall Heat Flux Profile

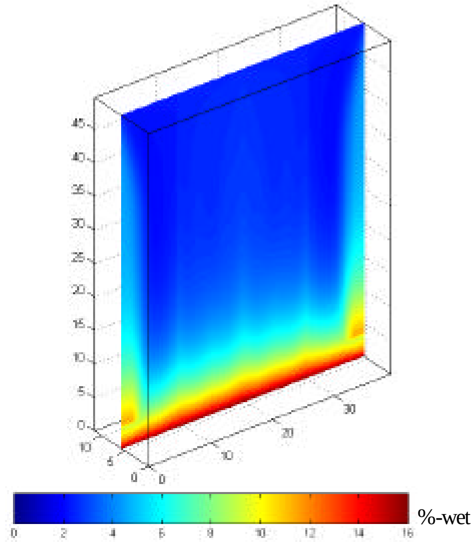


Figure 7.3.5 Furnace Centerline O_2 Profile

As a result of the Figure 7.2.1 modular scale-up approach, and with the exception of the two elevations of INTREX^{TM} heat exchangers, the boiler reflects a conventional arrangement of proven components. To keep the INTREX^{TM} heat exchangers at commercially proven sizes, and to eliminate equipment congestion along the sidewalls, they were divided into 16 units and, as shown in Figure 7.3.6, placed one above the other rather than side by side. This arrangement also provides a convenient means for increasing INTREX^{TM} heat transfer surface, and, for the Case 2 steam conditions, eliminated the need for furnace internal superheater panels.

Solids collected by the Compact Separators pass through the upper eight INTREX^{TM} cells and then cascade down into the lower eight INTREX^{TM} cells for return to the furnace. Slots in the lower furnace walls adjacent to the INTREX^{TM} cells allow hot solids from the lower furnace to fall into the lower cells (internal solids circulation) to increase their temperature for increased heat transfer to the lower INTREX^{TM} tube bundles. Solids can be bypassed around both upper and lower INTREX^{TM} cells by controlling the aeration rate to their lift legs. Figure 7.3.7 illustrates the openings in the furnace walls for internal solids circulation to the lower INTREX^{TM} cells.

In a CFB boiler the air flow rate and, hence, fluidizing velocity varies with load/coal firing rate until a minimum, turn down design value is reached. Reduced flue gas velocities result in reduced solids circulation rates, reduced upper furnace temperatures (Figure 7.3.8 illustrates the latter), and reduced INTREX^{TM} bed temperatures, especially in the lower level. To maintain both superheat and reheat temperatures with a cascading INTREX^{TM} arrangement, the finishing superheater (SH-IVa/b) was placed in the upper INTREX^{TM} level, and the intermediate superheater and finishing reheater were located in the lower level where internal circulation was used to augment their performance. Figure 7.3.9 illustrates this effect (RH-II duty was significantly increased) but also shows a reduction in finishing superheater duty; the internal circulation reduces the furnace exit temperature yielding lower bed temperatures and, hence, reduced heat absorption in the upper INTREX™ cells. To maintain the superheater outlet temperature at its desired value, the coal firing rate will be increased.

As a result, by combining a stacked INTREX™ configuration with internal solids circulation and a parallel pass HRA, superheat and reheat temperatures can be maintained at full load values over the 40 to 100 percent load range, a range significantly larger than the 50 to 100 percent range of PC boilers.

Although the Figure 7.3.6 INTREX™ stacking arrangement is new, the design of each individual INTREX™ is conventional (see Table 7.3.3 for comparison to other units); with the solids horizontal transfer distances continuing to be minimized, and with vertical lift chutes and bypass chutes still being used to control solids transfer and circulation rates, the move to 800 MWe does not present any scale-up issues.

Table 7.3.3 CFB INTREX™ Comparison

	800 MWe CFB	£agisza	Turow 4-6	JEA
Number of HXs	12	8	8	6
Heat Duty, MW_t	4x29, 4x43, 4x25	4x18, 4x17	4x12, 4x10	4x19, 2x32

Steam – Water Circuitry Arrangement

The 800 MWe CFB boiler is a once through type unit designed for sliding pressure operation. As with the 400 MWe unit, the furnace enclosure walls are fabricated from smooth tubing whereas the evaporative full height wing walls, receiving heat from two sides, are made from rifle tubing. Figure 7.3.10 shows the boiler's steam-water circuitry arrangement. Feedwater enters the CFB boiler through a bare tube economizer located in the HRA. From there the feedwater passes through the enclosure walls of the INTREX™ heat exchangers and proceeds to the evaporator surfaces consisting of the furnace four enclosure walls and six full height wing walls located inside the furnace. The furnace surfaces are swept in a single pass and their dry steam proceeds to and through water/steam separators. From there the steam passes through the tubes that form the furnace roof and proceed in succession through the support tubes of the convection pass superheater, the convection pass enclosure walls, and tube coils of the convection path superheater; these tube surfaces represent the first stage of superheating, e.g., SH-1. After SH-1, the steam flows in parallel through the walls of the CFB's eight solids separators, and these form the second stage of superheating, e.g., SH-2.

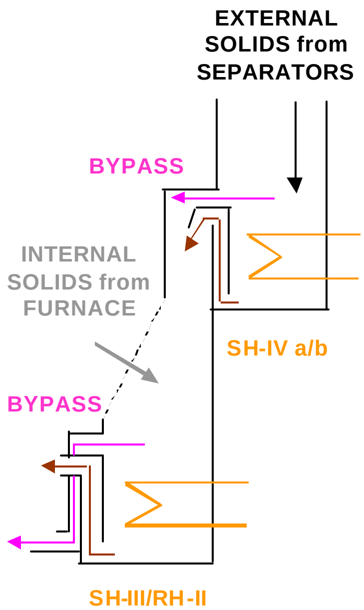


Figure 7.3.6 Cascading INTREX™ Arrangement

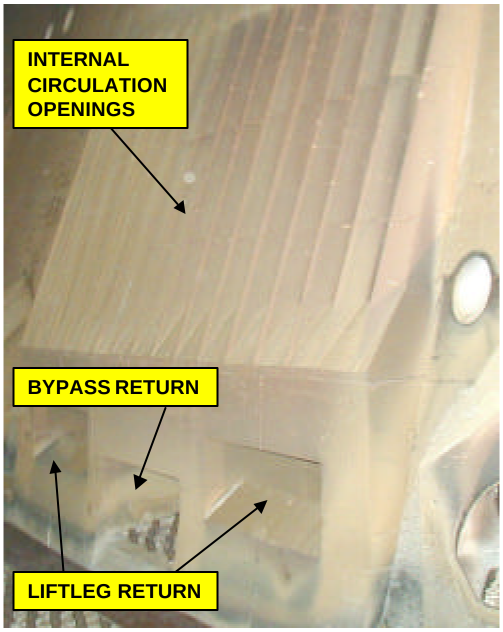


Figure 7.3.7 Furnace Wall Openings for INTREX™

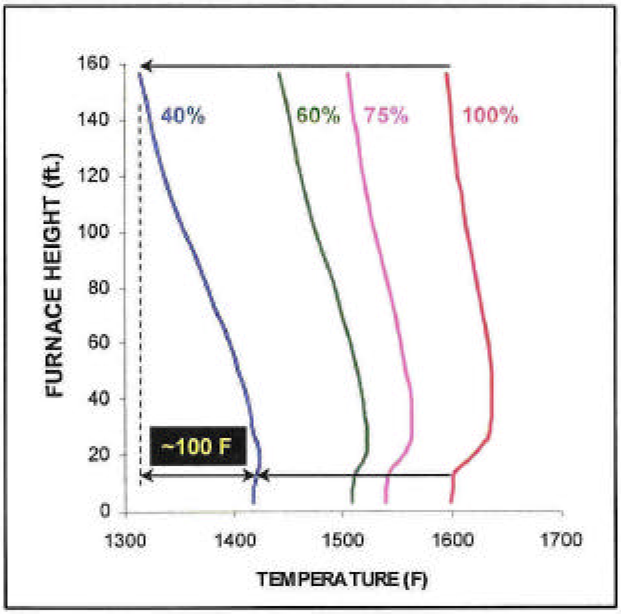


Figure 7.3.8 Furnace Temperature Profile

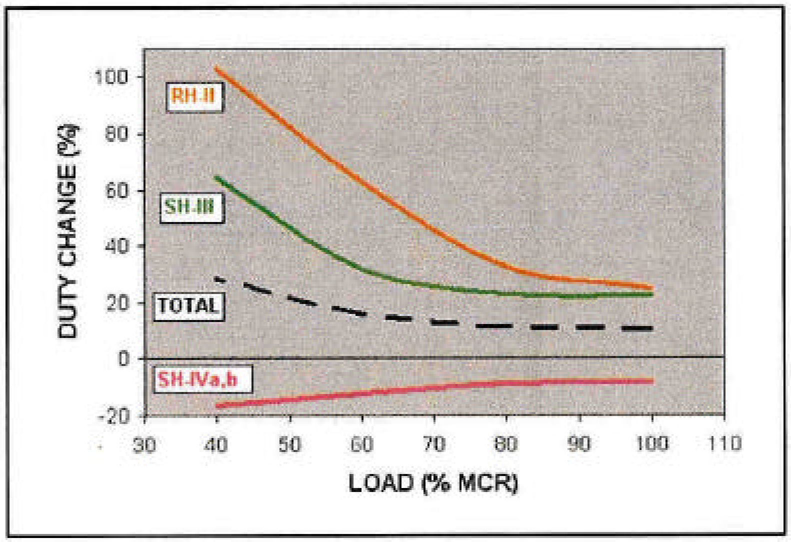


Figure 7.3.9 INTREX™ Duty Change with Internal Solids Circulation

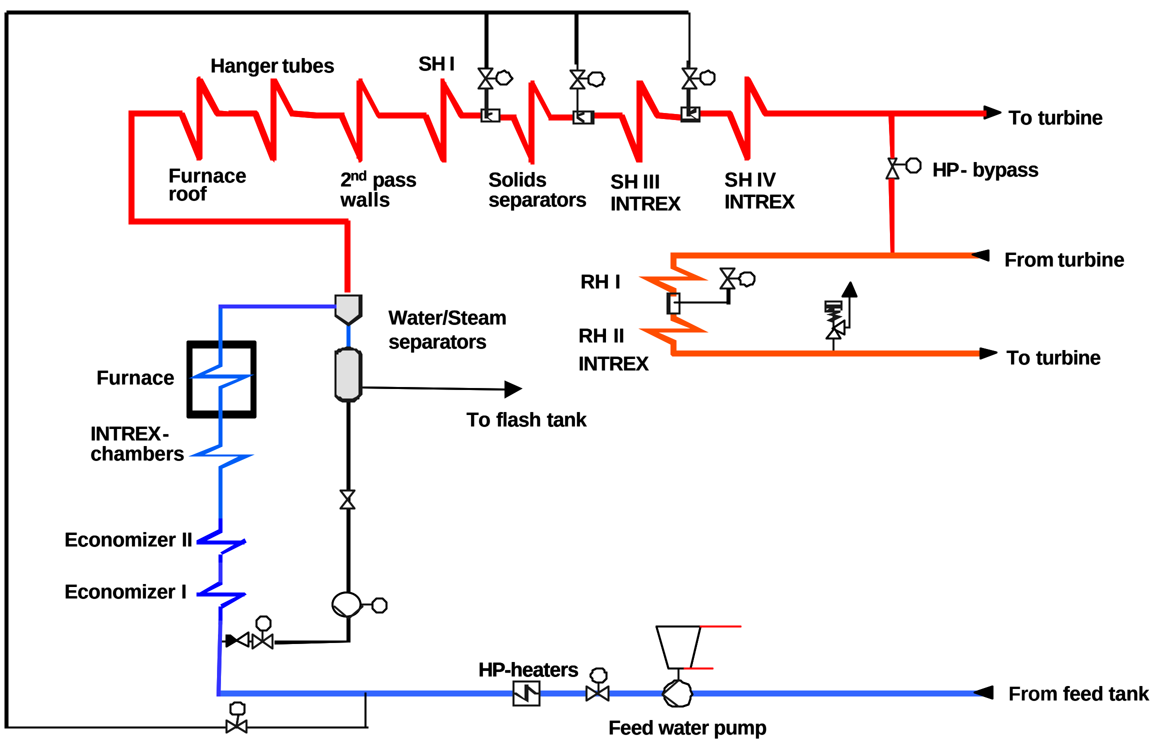


Figure 7.3.10 Steam-Water Circuitry of 800 MWe CFB Boiler

Following this stage, the steam is led to four INTREX superheaters located on one side of the furnace that form SH-3. Final superheating is carried out in SH-4, located in four INTREX superheaters above them. By stacking the superheaters, the eight INTREXs can be easily accommodated along one side wall and the finishing superheater is exposed to the hottest solids thereby minimizing the amount of tube surface required. The main steam temperature is controlled with a two-stage feed water spray, and by adjusting fuel feeding.

After passing through the high-pressure turbine, steam is returned to the boiler for reheating. The cold steam first passes through the first-stage reheater, e.g., RH-1 located in the HRA convection pass and then undergoes final reheat in the four INTREX heat exchangers (RH-2) located on the boiler wall opposite SH-3. The HRA incorporates a parallel gas path arrangement and its discharge dampers proportion the flue gas flow over its paths to control the RH-2 outlet temperature.

During start-up and shut-down, when the boiler is operating at subcritical pressure, a circulation pump is used to provide a minimum water flow through the evaporator tubes. The two-phase flow from the outlet headers of the evaporator walls is collected in vertical water/steam separators, where the water is separated from the steam and led to a single water-collecting vessel.

Boiler Materials

The material requirements for most sections of the boiler are conventional and normal boiler materials can be used. The furnace and solids separator panels, for example, can be manufactured of materials that do not require post-weld heat treatment. Austenitic steel Super 304 H is required for the final superheater and X11CrMoWVNb911 has been specified for the high temperature final superheater collection header and main steam pipe. The reheaters and remaining high-temperature superheaters will be furnished in TP347HFG.

Table 7.3.4 Pressure Part Materials for 800 MWe USC CFB Boiler

Heat exchanger tubes:		
Heat surface	*Tube material*	*Header Material*
Economizer	15Mo3	15NiCuMoNb5
Furnace walls	13CrMo44	15NiCuMoNb5
		13CrMo44
Superheaters and	13CrMo44	13CrMo44
reheaters	7CrMoVTiB1010	X10CrMoVNb91
	X20CrMoV121	X11CrMoWVNb911
	TP347HFG	
	Super 304 H	
Steam piping:		
Main steam pipe		X11CrMoWVNb911

Coal Feed
Coal, crushed to a nominal top size of 1/2 inch, is stored in four four-day silos positioned along the front wall of the boiler. Chain feeders under each silo meter the coal feed rate and drop the fuel onto four chain conveyors (two along each furnace sidewall) which, in turn, deliver the coal to a total of 16 drop chutes/screw feeders.

Sorbent Feed
Limestone with a 2-inch top size is stored in two silos positioned adjacent to each furnace side wall; the silos have a combined holding capacity of four days of limestone with the unit operating at full load. Limestone is withdrawn from the silos, milled to nominal top size of 600 microns, and rotary feeders meter the limestone flow into pneumatic transport systems that deliver the sorbent to 16 feed points. The limestone is concentrically injected into the furnace through selected lower level secondary air ports.

Draft System
Pairs of radial fans with inlet guide vane control are used for primary and secondary systems. Balanced draft operation is provided by two (2) axial flow, induced draft fans positioned downstream of a baghouse filter. Start-up burner air, INTREX^{TM} fluidization air, and wall seal aeration air is provided by four (4) centrifugal blowers. The flue gas exiting from the boiler is cooled in two parallel rotary/regenerative air heaters. The air heaters incorporate a tri-sector design, are approximately 55 feet in diameter, and cool the flue gases to 267ºF for discharge to a baghouse filter.

Bottom Ash System
A total of two stripper/coolers are provided (one adjacent to furnace front and rear walls) to cool and recover heat from the ash that drained from the furnace to maintain its inventory of circulating solids. Cooling and heat recovery is achieved by transferring ash sensible heat into the cold primary air used for fluidization, and by tube bundles through which low temperature condensate is passed. Ash removal rates are controlled by rotary valves that drop the 500ºF ash onto two drag chain conveyors that run the length of the furnace. For additional ash removal capacity and for occasional removal of ash from the center of the furnace, two screw coolers are also provided with drain inlets positioned near the center of the furnace.

7.4 Balance of Plant Systems

The balance of plant systems of the nominal 800 MWe CFB boiler are, with the exception of higher capacities/flow rates, essentially identical to those of the 400 MWe CFB boiler. For a description of the systems the reader is referred to Section 5.3.

7.5 Plant Cost and Economics

The 740.5 MWe USC CFB boiler system shown in Figure 7.3.1, complete with silos, limestone milling, coal and limestone feeding, CFB boiler, air heater, fans, flues, ducts, ash coolers, ash conveyors, and structural steel, is estimated to cost, delivered to the site and erected with union labor, $367.1 million in January 2006 dollars. In Table 7.5.1 the CFB system costs are shown along with the balance of plant cost elements and the plant has a bare erected cost (equipment plus field labor and materials) of $761.3 million. Adding 10 percent for architect/plant engineering, construction management, home office costs, and fee, plus 10 percent for project contingency, yields a total plant cost of $921.1 million or $1,244/kW.

As discussed in Section 3, the TPC assumes over night construction and Table 7.5.2 adds $144.3 million for interest during construction to obtain a TPI of $1,065.4 million. The addition of start up costs, inventory capital, land, etc. yields a TCR of $1,097.3 million. O&M costs, operating costs, and fuel costs are also shown and together with the levelized fixed carrying charge yield a 20 year levelized cost of electricity of $44.08/MWhr.

Reference [4-1] estimated that a PC plant operating with conventional, supercritical pressure conditions (3500psig/1050ºF/1050ºF) and producing 401.8 MWe of net power would cost $1,173/kW in January 1998 dollars. A 550 MWe update of that plant is in preparation for the DOE and, it is believed it will show a new total plant cost of approximately $1,350/kW in January 2006 dollars with a 10 year levelized cost of electricity of approximately $50/MWhr. Recognizing that the USC CFB plant is larger in size, which gives the CFB plant an economy of scale advantage, and that many assumptions are involved in calculating plant performance, costs, and economics, a comparison of values calculated by different investigators must be done with caution. With the nominal 800 MWe USC CFB plant coming in with a TPC of $1,244/kW and a levelized cost of electricity of $44.08/MWhr, a comparison of the two plants indicates CFB boilers will remain competitive with PC plants in both large sizes as well as under USC steam conditions.

Table 7.5.1 Total Plant Cost Summary – Nominal 800 MWe USC CFB Boiler

Equipment Plus Field Labor & Materials		Thousands of Jan 2006 Dollars	$/KW
USC CFB Boiler System*		367,132	
Balance of Plant			
Fuels handling & storage	17,817		
Sorbent handling systems	10,426		
Ash handling & storage	9,423		
Baghouse	19,002		
FGD	0		
Stack	7,738		
Steam turbine-generator	65,525		
Feedwater heaters	4,155		
Condenser	4,580		
Pumps	5,987		
Cooling tower	5,090		
Water treatment systems	4,341		
Miscellaneous equipment	461		
Piping systems	52,485		
Distributed control system	2,875		
Continuous emission monitors	398		
Local control systems	2,163		
Electrical - transformer/bus ducts	4,491		
Electrical - switchyard	9,221		
Electrical - switchgear, MCCs, etc	22,412		
Electrical - cables/wiring/lighting/communic	52,622		
Buildings	31,966		
Foundations	32,533		
Equipment insulation	9,376		
Fire protection	8,278		
Sitework	10,766		
		394,131	
Total Bare Erected Cost		**761,263**	
Architect Engineering, Constr Mngmnt, Home Office,& Fee		76,126	
Project Contingency		83,739	
Total Plant Cost		**921,128**	**1244**

*Includes silos, limestone milling, coal and limestone feed systems, CFB boiler, air heater, ash cooler, ash conveyors, fans, flues, ducts, and structural steel

Table 7.5.2 Capital Investment & Revenue Requirement Summary – Nominal 800 MWe USC CFB Boiler Plant

TITLE/DEFINITION			
Case:	2	Steam Turb:	4336psig/1112F/1148F
Plant Size:	740.5 MWe (net)	Heat Rate:	8,263 BTU/kWhr
Fuel (type):	Illinois No 6 Coal	Fuel Cost:	$1.34/MMBtu
Design/Construction:	44 Months	Book Life:	20 Years
TPC (Plant Cost) Year:	Jan-06		
Capacity Factor:	85.0%		

CAPITAL INVESTMENT:		**$x1000**	**$/kW**
Bare Erected Cost (Process Capital & Facilities)		761,263	
Engineering (incl. Constr Mngmnt, H.O., & Fee)		76,126	
Project Contingency		83,739	
	TOTAL PLANT COST	**921,128**	**1,244**
	AFUDC	144,263	
	TOTAL PLANT INVESTMENT	**1,065,391**	**1,439**
Royalty Allowance		0	
Start Up Costs		24,741	
Working Capital		7,209	
Debt Service Reserve		0	
	TOTAL CAPITAL REQUIREMENT	**1,097,341**	**1,482**
OPERATING & MAINTENANCE COSTS (2006)			
Operating Labor		5,928	
Maintenance Labor		4,706	
Maintenance Material		15,479	
Administrative & Support Labor		1,443	
	TOTAL OPERATION & MAINTENANCE (2006)	27,556	
	FIXED O&M (2006)	**24,800**	
	VARIABLE O&M (2006)	**2,756**	
CONSUMABLE OPERATING COSTS, LESS FUEL (2006)			
Water and Treatment		4,857	
Limestone		5,893	
Ash Disposal		5,558	
Other Consumables		1,800	
	TOTAL CONSUMABLES (2006)	**18,108**	
BY-PRODUCT CREDITS (2006)		0	
FUEL COST (2006)			
Coal	**FUEL COST (2006)**	**61,050**	

		1st Year (2009)	**20 Year Levelized**
PRODUCTION COST SUMMARY		**$/MWhr**	**$/MWhr**
	Fixed O&M	4.50	4.50
	Variable O&M	0.50	0.50
	Consumables	3.28	3.28
	By-Product Credit	0.00	0.00
	Fuel	11.07	11.07
	TOTAL PRODUCTION COST (2006)	**19.35**	**19.35**
	LEVELIZED 20 YEAR CARRYING CHARGES (Capital)*		**24.73**
	LEVELIZED 20 YEAR BUSBAR COST OF POWER		**44.08**

***Levelized Fixed Charge Rate = 12.5%**

8.0 800 MWe Advanced USC CFB Boiler

8.1 CFB Steam Temperatures for the Future

Research and development work in once-through boiler technology has set a goal of achieving 1300ºF superheat and reheat steam temperatures at pressures up to 5000 psig. Per Figure 8.1.1 the CFB boiler furnace exit gas temperature (FEGT) is relatively low compared to a PC boiler. With the temperature difference between gas and steam reduced, there is concern that a CFB boiler will require an excessive amount of tube surface to meet these high steam temperatures and result in a costly, unconventional design.

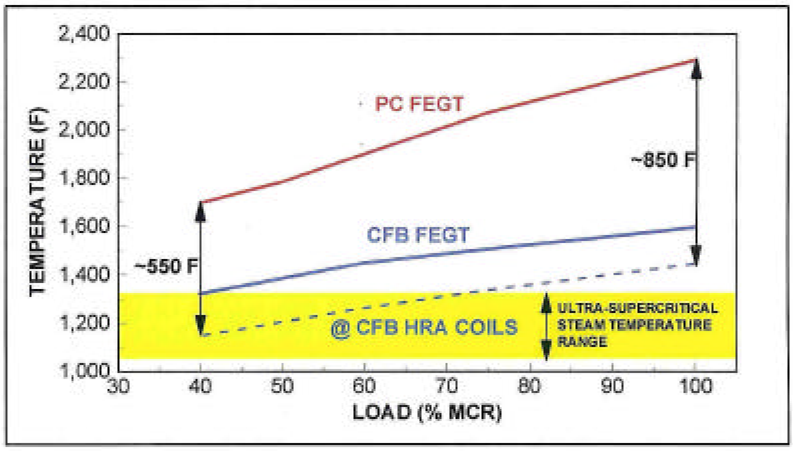


Figure 8.1.1 Comparison of PC and CFB Furnace Exit Gas Temperatures

Assuming materials can be developed for these advanced conditions that would result in pressure part thicknesses comparable to those of present day supercritical units, and, keeping the CFB boiler within normal design/operating parameters, an effort was undertaken (Case 3) to develop a conceptual design of a CFB boiler for the above advanced steam conditions. Section 8.2 identifies the operating conditions of an advanced USC power plant and Section 8.3 presents a conceptual design of its CFB boiler.

8.2 Plant Performance and Emissions

Figure 8.2.1 presents a full load heat and material balance for the Case 3 plant; operating conditions/state points are shown in this balance for each of the major plant components and the plant utilizes a single reheat steam turbine with 5061 psig/1292°F/1328°F throttle conditions. Steam enters the high-pressure turbine at a rate of 4,291 Mlb/h and after reheating is delivered to the IP turbine at a rate of 3,508 Mlb/h at 955 psig and 1328°F. The turbine exhausts to a single-pressure condenser operating at 2.0 inches Hga backpressure at full load. The feedwater train consists of eight closed feedwater heaters (five low-pressure and three high pressure), and a deaerator. Extractions for feedwater heating, deaerating, and the boiler feed pump are taken from the HP, IP, and LP turbine cylinders, and from the cold reheat piping.

The plant has been designed to the same emissions requirements as the other CFB plants and, as such, it uses limestone feed to the CFB boiler for in situ sulfur capture (96 percent SO_2 removal), staged combustion to control NOx emissions to below 0.16 lb/MMBtu, and a pulse jet baghouse filter to remove over 99.9% of the dust in the flue gas.

Tables 8.2.1 and 8.2.2 summarizes the performance and emissions of the plant at full load. The plant net power output is 768.2 MWe and it operates with an efficiency of 43.3 percent (HHV), which is a heat rate of 7,878 Btu/kWh. The move to advanced USC, e.g., higher pressure and higher superheat and reheat temperatures increases the plant efficiency by approximately 5 percent (43.3 versus 41.3) over that of the Case 2 plant. As a result, the plant emissions are similarly reduced by about 5 percent.

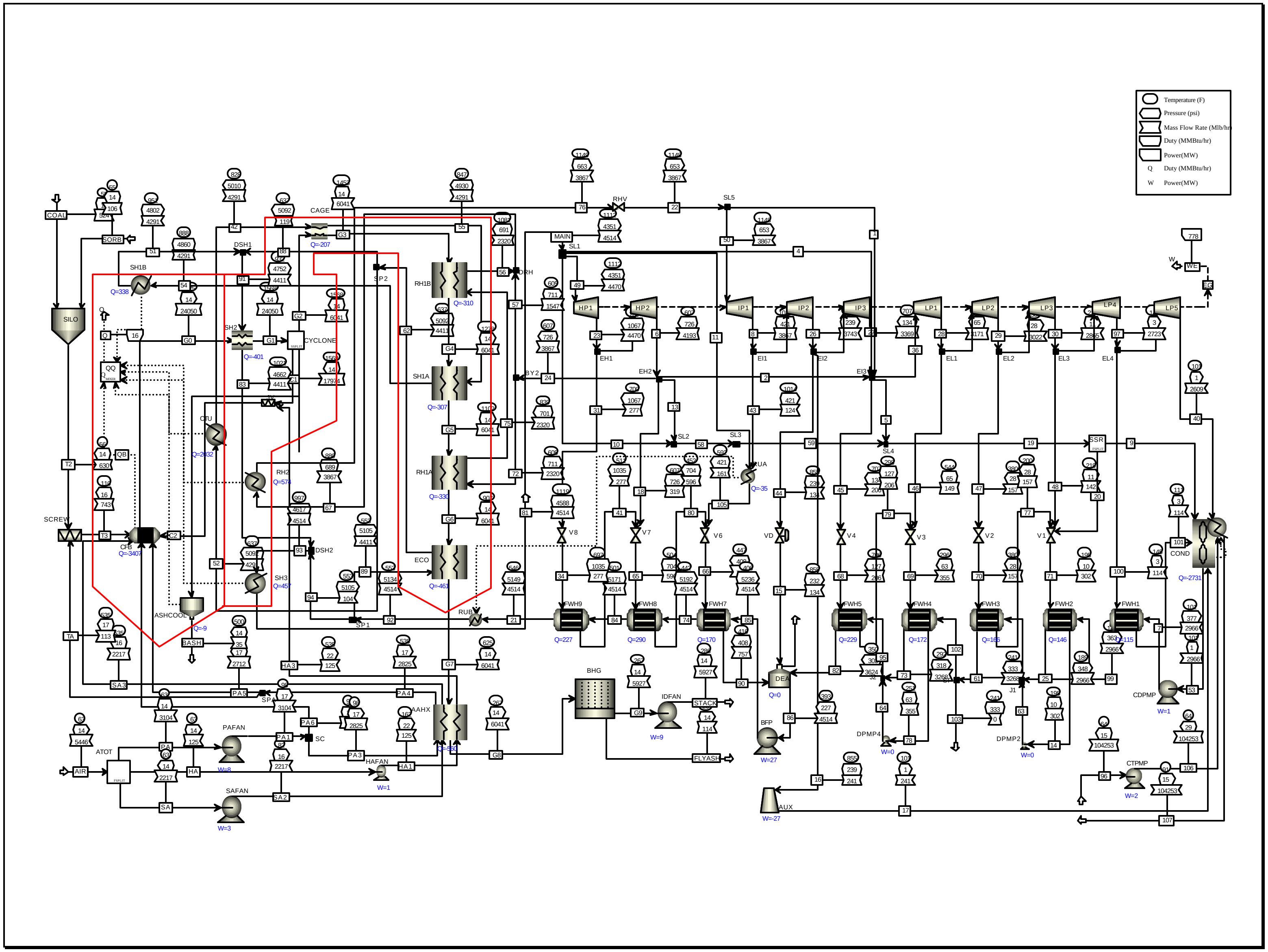


Figure 8.2.1 Case 3 – 800 MWe Advanced USC CFB Plant Heat & Material Balance

Table 8.2.1 Advanced USC 800 MWe CFB Plant Performance

STEAM CYCLE	
Throttle Pressure, psig	5,061
Throttle Temperature, F	1,292
Reheat 1 Intlet Temperature, F	1,328
Reheat 2 Inlet Temperature, F	N/A
POWER SUMMARY, kWe	
Gross Power at Generator Terminals	804,608
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	267
Coal Feeding	291
Limestone Handling & Feeding	280
Pulverizers	
Condensate Pumps	1,117
Main Feed Pump (Note 1)	27,788
Booster Feed Pump	
Miscellaneous Balance of Plant (Note 2)	3,000
Primary Air Fans	8,888
Forced Draft Fan	2,634
Induced Draft Fan	6,216
High Pressure Blower	2,544
Baghouse	174
SNCR	
Air Preheater	14
FGD Pumps and Agitators	
Steam Turbine Auxiliaries	1,000
Circulating Water Pumps	4,196
Cooling Tower Fans	2,885
Transformer Loss	1,900
Ash Handling	1,002
Total	64,196
Total with Main Feed Pump Deduct	36,408
NET VALUES	
Net Power, kWe	768,200
Net Efficiency [HHV], %	43.3
Net Heat Rate [HHV], Btu/kWhr	7,878
CONDENSER COOLING DUTY, MMBtu/hr	2,570
CONSUMABLES	
As Received Coal Feed, lb/hr	518,757
Sorbent Feed, lb/hr	104,261
Ammonia Feed, lb/hr	N/A
Ash, lb/hr	147,632
Scrubber Slurry Discharge, lb/hr	N/A

Note 1 - Driven by auxiliary steam turbine

Note 2 - Incudes plant control systems, lighting, HVAC etc

Table 8.2.2 Advanced Ultra Supercritical 800 MWe CFB Plant Emissions

	lbs/MMBtu	lbs/MWh	Tons/Year*
SO2	0.171	1.351	3,863
NOx	0.160	1.260	3,605
Particulate	0.008	0.066	187
CO2	204	1,609	4,602,463

Note 1: CFB operates with 96% sulfur capture and does not include a polishing scrubber
Note 2: CFB operates without SNCR which would reduce NOx to 0.048 lb/MMBtu
* Assumes 85% capacity factor

8.3 CFB Boiler Conceptual Design

General Arrangement

The operating conditions of the advanced USC 800 MW_e CFB boiler are listed in Table 8.3.1. The CFB boiler operates with a nominal 1600ºF bed/furnace temperature and combusts coal at the rate of 518.8 Mlb/hr with 20 percent excess air to produce 5,284 psig 1297ºF steam at a rate of 4,334 M lb/hr. Limestone is injected into the furnace at a rate of 104.3 Mlb/hr for a calcium to sulfur molar feed ratio of 2.4 and 96 percent sulfur capture.

In a PC boiler, the finishing superheater consists of a loop or several loops of vertical pendant tubing typically located near the furnace exit above the furnace nose (see Figure 8.3.1). At this location the flue gas temperature is about 2300ºF which yields a gas to steam temperature difference of approximately 1000ºF. Large CFB boilers typically have cooled crossover ducts that collect the flue gas from several solids separators for delivery to the convective path HRA (see Figure 8.2.2). With the CFB furnace exit temperature being approximately 1600ºF and, allowing for gas cooling in the cross over duct, the gas to the steam temperature difference entering the CFB HRA will be less than 300ºF. Because of this low temperature difference together with low gas-to-tube heat transfer coefficients, the gas path is not a good location for the CFB's finishing superheater and reheater. Instead these surfaces will be located in the INTREX TM fluidized bed heat exchangers.

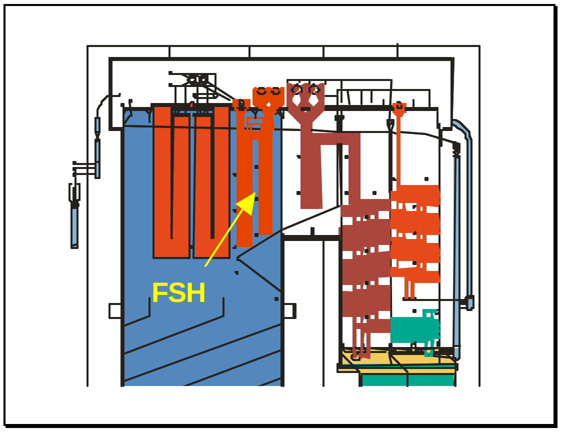


Figure 8.3.1 PC Finishing SH Location

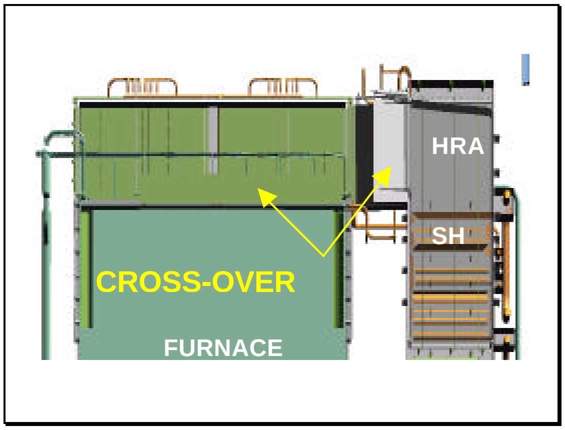


Figure 8.3.2 CFB Convection SH Location

Table 8.3.1 800 MWe Advanced USC CFB Boiler Operating Conditions

Outlet Steam Conditions:		
Main Steam Flow Rate	Mlb/hr	4,334
Main Steam Temperature	F	1,297
Main Steam Pressure	psia	5,284
Reheat Steam Flow Rate	Mlb/hr	3,508
Reheat Steam Temperature	F	1,328
Reheat Steam Pressure	psia	955
Feedwater Inlet Temperature	F	629
H&M Balance Parameters:		
Flow Rates:		
Flue Gas	Mlb/hr	5,864
Combustion Air	Mlb/hr	5,389
Coal	Mlb/hr	518.8
Limestone	Mlb/hr	104.3
Total Ash	Mlb/hr	147.6
Temperatures:		
Furnace Exit	F	1,625
Flue Gas Entering Air Heater	F	800
Flue Gas Leaving Air Heater	F	268
Bottom Ash	F	500
Excess Air	%	20

Including silos, fans, and airheater the boiler will occupy an approximate 200 feet by 330 feet foot print and be top supported from structural steel approximately 250 feet above grade. The CFB boiler is very similar in size and arrangement to that of the 800 MWe unit shown in Figures 7.3.1 through 7.3.3. As a result, the latter's drawings have been marked up to show the changes required for advanced supercritical operation. Figures 8.3.3 and 8.3.4 present front and side views of the advanced USC boiler and it incorporates:

a) 4 coal silos supplying coal to 16 furnace feed chutes
b) 3 full height furnace evaporative wing walls parallel to front and back walls
c) 3 full height furnace evaporative wing walls parallel to the side walls
d) 10 platen superheater panels
e) 8 Compact Solids Separators
f) a parallel pass HRA
g) 2 elevations of 8 INTREX™ Fluidized Bed Heat Exchangers
h) 2 bottom ash stripper coolers (one on each end wall)

CASE 3: 800 MWe Advanced USC CFB Boiler Design Changes
Front View

DELETE:

1. **2m from Furnace Height**
2. **Full Height Evaporator Walls**

ADD:

1. **Ten(10) Platen Superheaters**
2. **Loop of Tubing to Superheater IVa & IVb**
3. **Less Conductive, Thicker Refractory**

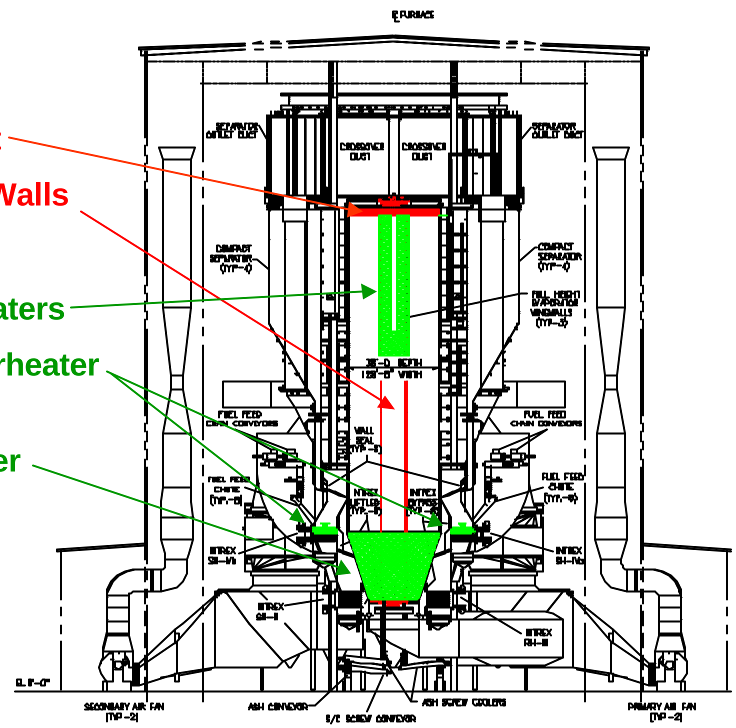
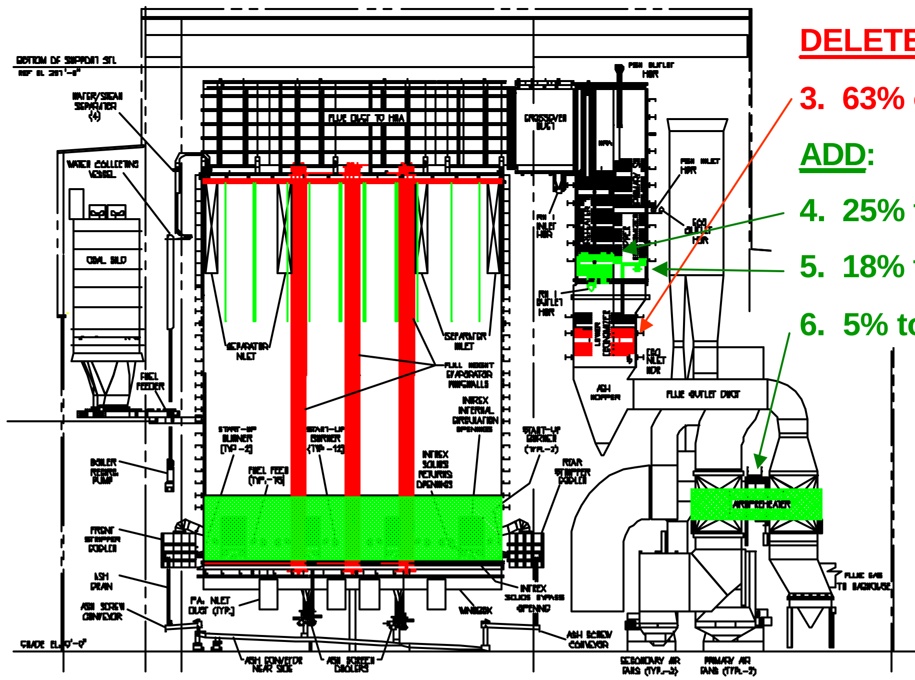


Figure 8.3.3 Front View of 800 MWe Advanced USC CFB Boiler

CASE 3: 800 MWe Advanced USC CFB Boiler Design Changes Side View



DELETE:

3. 63% of Lower Economizer

ADD:

4. 25% to Reheater I
5. 18% to Upper Economizer
6. 5% to Air Heater

Figure 8.3.4 Side View of 800 MWe Advanced USC CFB Boiler

In going from the Case 2 USC to the Case 3 advanced USC steam conditions there is a considerable shift in economizer, evaporator, and superheater duties. As shown in Figure 8.3.5 there is a noticeable increase in superheater duty and a corresponding reduction in economizer and evaporator duty. These shifts are required to:

- limit the steam temperature leaving the furnace enclosure wall evaporator so that high end alloy materials, which require special welding procedures for the membrane wall construction (fin welded to tube), are not required.
- locate the start and completion of evaporation so that issues related to two-phase flow (phase separation, departure from nucleate boiling, dryout, and dynamic instability) are not experienced.

Quantification of the duty shift at the minimum BENSON load of 40 percent is shown in Figure 8.3.6. With variable pressure operation, the BENSON load is at a subcritical pressure where there are distinct preheat, evaporation, and superheat duty requirements.

In order to accommodate the duty shifts required for the Case 3 operating conditions, the changes noted in Figures 8.3.3 and 8.3.4 were required.

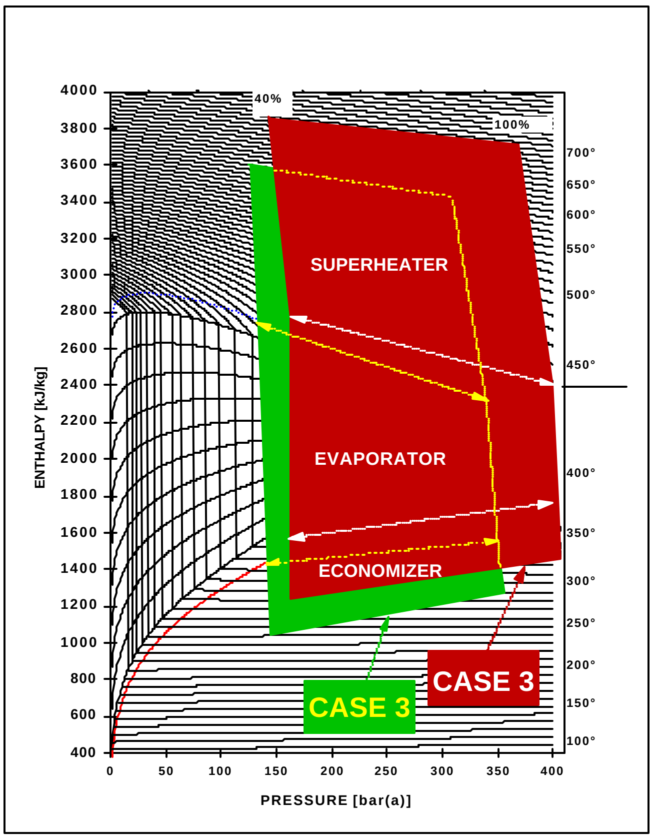


Figure 8.3.5 Case 2 to 3 Duty Distribution Shift

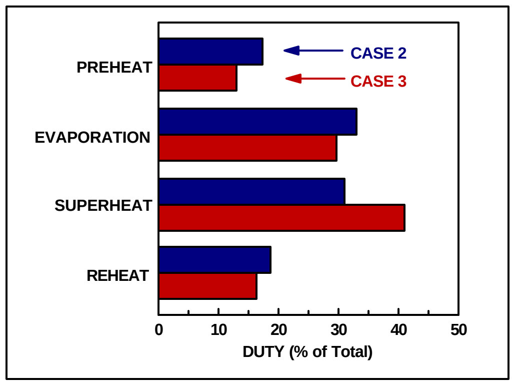


Figure 8.3.6 40% Load Duty Comparison

The changes can be summarized as follows:

To reduce evaporator duty:

- Furnace height was reduced by approximately 6.5 feet
- Full height evaporator wingwalls were removed
- Less conductive, thicker refractory is used in the lower furnace

To increase superheater duty:

- In-furnace platen superheaters (10) were added upstream of INTREX^{TM} SH-III
- A loop of tubing was added to upper INTREX^{TM} SH-IV (now same number of tube elements in the upper and lower INTREX^{TM} cells)

To reduce reheater duty:

- Convection reheater surface increased (+25%); this change compensates for the reduced INTREX^{TM} RH-III duty resulting from higher steam temperatures and the increased INTREX^{TM} RH-IV duty that lowers the temperature of the solids cascading to RH-III

To reduce economizer duty:

- Upper economizer surface increased (+18%), lower reduced (-63%)
- Air heater surface increased (+5%); adjustment required to achieve stack temperature with reduced economizer duty (shifts more heat into high temperature furnace solids circulation loop)

With these changes, the evaporator inlet water is sufficiently subcooled over the load range, maximum evaporator outlet superheat is about 86 Btu/lb, and full reheat steam temperature is maintained down to approximately 45 percent load (1323°F at 40 percent load).

These results show that a CFB boiler can achieve/operate with advanced USC steam conditions (5,270 psig and 1300ºF) in a conventional configuration provided materials, with sufficient strength, outside corrosion resistance, and inside oxidation resistance, are available/ developed for these conditions.

9.0 Results and Discussion

The desire for high efficiency, coal-fired power generation has sparked electric utility interest in supercritical, ultra supercritical (steam temperatures typically 1100ºF and higher), and advanced ultra supercritical (steam conditions approaching 5000 psig and 1300ºF) steam cycles. The high efficiency advantages of supercritical (SC) and ultra supercritical (USC) pressure steam conditions have been demonstrated in the high gas temperature, high heat flux environment of PC boilers. For economies of scale these units are large in size and are frequently in the 800 to 1000 MWe range.

Circulating fluidized bed (CFB) boilers were first introduced in the 1970s and are an alternative to PC boilers. Exhibiting multi-fuel and low-grade fuel capabilities, low emissions, operating flexibility, and high reliability, they have steadily increased in size and, as of the writing of this report, the largest units in operation are the two 300 MWe, natural circulation, CFB boilers supplied by Foster Wheeler to the Jacksonville Electric Authority. Since CFB boilers operate with combustion temperatures and in sizes that are much lower/smaller than those of PC boilers (~1600ºF versus 3500ºF and 300 MWe versus 1000 MWe), the ability of CFB boilers to accommodate SC, USC, and advanced USC has been questioned. To address this, a study was conducted to develop and assess conceptual designs of supercritical CFB boilers and to estimate their plant performance and economics.

Reference [4-1] presented a conceptual design and determined the economics of a USC PC plant operating with 4500psig/1100ºF/1100ºF/1100ºF USC steam conditions that produced 399.7 MWe (net) with an efficiency of 41.4 percent. To permit a consistent comparison of technologies, the CFB study was conducted for the same site conditions i.e. Illinois No. 6 coal, Ohio River Valley, etc. and for the same SO_2 and NOx lb/MMBtu emission rates. In addition to the [4-1] 400 MWe double reheat case, the CFB study included single reheat in nominal 400 MWe and 800 MWe sizes. Assuming tubing and piping materials could be developed that would result in component thicknesses that would be similar to those of USC boilers, a nominal 800 MWe CFB design was developed for advanced USC steam conditions.

The move to 400 and 800 MWe supercritical CFB boilers represents a significant design change and scale-up. Items to be considered in such a scale-up are the design of:

1.) furnace/riser where combustion occurs
2.) the solids separators that remove entrained particulate from the combustion exhaust
3.) the HRA that cools the combustion exhaust gas exiting the separators for delivery to an air heater
4.) the fluidized bed heat exchangers that cool the particulate collected by the separators before their return to the base of the furnace
5.) the overall integration of the CFB boiler steam-water circuitry with the HRA and the furnace hot, circulating solids loop

The amount of particulate contained in the furnace flue gas decreases in going from the bottom to the top of the unit and, given sufficient height, can approach a constant minimum value. With wall heat transfer rates being proportional to the amount of particulate entrained in the gas, furnace heights are typically limited to about 165 feet to maximize the cost effectiveness of its heat transfer surfaces. Similar to the height limitation, there is also a furnace depth limitation. With primary combustion air admitted at the base of the furnace, and fuel and secondary air injected through the side walls of the boiler, the furnace depth is typically limited to approximately 40 feet to insure the side injections are distributed uniformly across the unit. With maximum allowable furnace heights and furnace depths established, the main remaining variable in the scale-up process is the width. By increasing the width of the furnace, the boiler cross sectional areas were increased to keep flue gas velocities at desired levels. As the cross sectional areas were increased, however, the ratio of furnace wall surface area to enclosed volume reduced. Since the furnace walls are used for boiling/evaporation, additional evaporative surfaces, e.g. wing walls that protrude into the furnace and are connected in parallel with the furnace walls in a single pass water flow arrangement, were added to the furnaces.

Maintaining a high separation efficiency in the CFB boiler's solids separators is key to achieving high combustion efficiency, reduced limestone consumption, and high sulfur capture efficiency.

Since the separation efficiency of these devices tends to decrease as physical sizes/diameters are increased, large CFB boilers will use the separator sizes proven most cost effective in smaller size units. Although a large CFB boiler will require a larger number of separators, they will be of a proven size and design. By applying them in nominal, 100 MWe furnace-separator module building blocks placed side by side and opposite each other, the 400 MWe and 800 MWe sizes were easily accommodated.

After passing through the furnace solids separators, the nominal 1600ºF CFB flue gas is cooled by the HRA for discharge to a downstream air heater. Consisting of convective tube bundles and cooled walls that superheat and reheat steam as well as preheat boiler feedwater (economizer), the CFB HRA arrangements were found to be typical of large PC boilers and will not pose any scale-up issues. The heat content of the flue gas exiting the CFB's separators, however, is not large enough to satisfy the superheat and reheat needs of a large plant and so superheat wing walls had to be added to the furnaces. With evaporative surfaces already added to the furnaces, the space for this additional surface was limited and the balance of the required superheat and reheat tube surfaces were placed in INTREXs™ fluidized bed heat exchangers located under the separators; these exchangers provide a dense "package" of highly efficient heat transfer surfaces and, having been utilized on several Foster Wheeler CFB boilers, they pose no scale-up issues.

Solids collected by the separators and passing/cascading through the INTREXs, (called external circulation) are cooled and, with the temperatures of succeeding beds being reduced, tube surfaces must be arranged to maximize the available bed to tube temperature differences so tube surface area requirements can be minimized. Foster Wheeler has patented a unique design arrangement that allows hot solids to be brought directly from the furnace into the INTREXs (called internal circulation). By integrating both internal and external circulation, INTREX operating temperatures were increased yielding higher bed to tube temperatures that enabled the CFB to accommodate even the 1300ºF steam temperatures of the advanced USC case. Part load analyses showed that, with the INTREXs, superheat and reheat temperatures could be maintained down to approximately 40 per cent load whereas comparable PC boiler turn down is limited to approximately 50 percent load.

Plant heat and material balances were prepared for each of the study cases and conceptual designs were developed for three different CFB boilers. The CFB conceptual designs addressed each of the above concerns and, with the designs reflecting conventional design practices, an R&D development effort will not be required to support their deployment. Where applicable, balance of plant equipment was sized, components were cost estimated, and overall plant performance and economics were determined.

Table 9.1 summaries the results of the study. The efficiencies of the nominal 400 MWe double reheat USC CFB and PC plants were found to be comparable (41.2 versus 41.4 percent). Since [6-1] has shown double reheat to be one of the most expensive ways to increase plant efficiency, and, since the CFB plant showed only a 0.6 percentage point efficiency gain through it, the economics of the double reheat case were not determined.

Table 9.1 USC CFB Boiler Plant Performance and Economics

Case	-------------Steam Turbine Conditions------- Throttle Press psig	Sht Temp F	Rht Temp F	Gross Power MWe	Auxiliary Power* MWe	Net Plant Output MWe	HHV Efficiency %	Total Plant Costs** $/KW	Cost of Electricity $/MWhr	% Efficiency Emission Reduction***
1A	4500	1100	1100	426.3	21.4	404.9	40.6	1,551	52.21	8.8
1B	4500	1100	1100/1100	425.8	23.4	402.4	41.2			10.2
2	4336	1112	1148	777.6	37.2	740.5	41.3	1,244	44.08	10.4
3	5061	1292	1328	804.6	36.4	768.2	43.3			14.5

*Boiler feed pump has steam turbine drive
**January 2006 dollars
***Compared to a plant with 37% efficiency and the same net output and lb/MMBtu emission rate

The nominal 400 MWe (Case 1A) and 800 MWe (Case 2) single reheat USC CFB plants were single boiler-steam turbine plants with net outputs of 405 and 740 MWe; their total plant costs, which were calculated to be $1,551/kW and $1,244/kW respectively, exhibit a significant economy of scale. Reference [9-1] indicates that the costs of single unit plants typically scale on their capacity raised to the 0.6 to 0.7 power; based on gross electrical output, an exponent of 0.64 is observed to fit the CFB plant costs. This economy of scale also extends into the cost of electricity calculation yielding levelized values of $52.21/MWhr and $44.08/MWhr respectively. As discussed in Sections 5.4 and 7.5, the USC CFB plant costs are expected to be similar to those of comparable USC PC plants.

The single reheat 405 and 740 MWe USC CFB plants exhibit efficiencies of 40.6 and 41.3 percent, respectively, and, moving the latter to advanced USC conditions, increased its plant efficiency to 43.3 percent. Compared with a new subcritical pressure plant, which typically operates with about a 37 percent efficiency, the supercritical conditions studied will reduce power plant coal and ash flow rates, stack gas emissions, and CO_2 release rates by approximately 9 to 15 percent.

Key findings of the study are:

1.) Since CFB furnace heat fluxes are lower and more uniform than PC boilers:

   a. CFB furnace enclosure walls can be constructed from straight, self supporting, vertical tubes rather than the complex spiral wound tube designs of PC boilers that require a special support system and which would experience erosion in a CFB furnace
   b. CFB furnace walls can operate without internal rifling at water mass flow rates much lower than a PC boiler and still be protected from departure from DNB.
   c. With smooth tubes and lower water mass flow rates being used, CFB furnace wall frictional pressure losses are lower than hydrostatic pressure losses and:
      i. USC CFB boilers will require less boiler feed pump power than PC units

ii. CFB furnace walls will operate with a self compensating, natural circulation characteristic, wherein, an excessively heated tube will experience an increase in water flow that will minimize the tube-to-tube temperature differences that can lead to tube failures

2.) Large CFB boilers will be constructed from nominal 100 MWe type building block modules, each consisting of a section of furnace section linked to two solids separators placed side by side and then opposite each other to reach 400 and 800 MWe sizes.

3.) Including coal and limestone feed silos, air fans, and air heater, a 400 MWe USC CFB boiler will occupy a foot print approximately 180 feet by 275 feet and be supported by structural steel approximately 225 feet above grade.

4.) Including coal and limestone feed silos, air fans, and air heater, a nominal 800 MWe USC CFB boiler will occupy a foot print, approximately 200 feet by 300 feet and be supported by structural steel approximately 250 feet above grade.

5.) Computer model simulations of the 400 MWe and 800 MWe units have predicted furnace heat release patterns, heat flux profiles, pressure profiles, oxygen profiles, and maximum tube wall temperatures that are consistent with Foster Wheeler CFB boiler design standards.

6.) Part load analyses have shown that superheat and reheat steam temperatures can be maintained at full load values over the 40 to 100 percent load range, whereas, 50 to 100 percent is typical of PC boilers.

7.) Despite the CFB's relatively low ~1600ºF combustion temperature, the 1300ºF steam temperature of advanced USC cycles can be accommodated by operating Foster Wheeler's INTREX™ fluidized bed heat exchangers with patented internal solids circulation.

8.) The physical arrangements of the 400 MWe and 800 MWe USC units reflect conventional Foster Wheeler CFB boiler configurations and can be deployed without the need for R&D development work.

9.) The physical arrangement of the 800 MWe CFB boiler operating with advanced USC steam conditions also reflects conventional Foster Wheeler CFB design practices but will require the development of new tube/pipe materials.

10.) Use of advanced USC conditions (nominally 5061psig/1300ºF/1300ºF) will increase the efficiency of the 800 MWe CFB plant to 43.3 percent.

10.0 Conclusions

This study has shown that the move to 400 MWe and 800 MWe size USC CFB boilers is technically feasible, economically viable, and will involve minimal scale-up risk. Such large

CFB boilers will be constructed from nominal, 100 MWe type building block modules, each consisting of a furnace section linked to two solids separators placed side by side and then opposite each other to reach 400 and 800 MWe sizes.

The performance and economics USC CFB boiler plants will be similar to that of USC PC plants. The higher plant efficiencies that supercritical conditions provide will enable these plants to operate with less fuel consumption and a proportional reduction in waste ash flow rates, traditional stack gas pollutants, and CO_2 release rates; depending upon the supercritical conditions selected, the fuel and emission rates will be approximately 9 to 15 percent lower than a new, subcritical pressure plant operating with 37 percent efficiency.

Hence, supercritical CFB boilers will be a viable means for meeting the economic and environmental needs of the US electric utility industry for both the present and the future.

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12.0 Bibliography

N/A

13.0 Acronyms and Abbreviations

AFUDC	Allowance for Funds Used During Construction
BFB	Bubbling Fluidized Bed
CFB	Circulating Fluidized Bed
COE	Cost of Electricity
CO_2	Carbon Dioxide
DCS	Distributed Control System
DNB	Departure From Nucleate Boiling
FGD	Flue Gas Desulfurization
FEGT	Furnace Exit Gas Temperature
FSH	Finishing Superheater
Hg	Mercury
HHV	Higher Heating Value
HP	High Pressure
HRA	Heat Recovery Area
INTREX^{TM}	Integrated Recirculating Heat Exchanger
IOU	Investor Owned Utility
IP	Intermediate Pressure
IRR	Internal Rate of Return
JEA	Jacksonville Electric Authority, Jacksonville Florida
LP	Low Pressure
NOx	Oxides of Nitrogen
OTU	Once Through Unit
O&M	Operating and Maintenance
PC	Pulverized Coal
RH	Reheater
RPM	Revolutions per Minute
SC	Supercritical
SCR	Selective Catalytic Reduction
SH	Superheater
SO_2	Sulfur Dioxide
TAG	Technical Assessment Guideline
TPC	Total Plant Cost
TPI	Total Plant Investment
TCR	Total Capital Requirement
US	United States
USC	Ultra Supercritical
VHP	Very High Pressure